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UNITED STATES
DEPARTMENT OF THE INTERIOR

DRAFT
ENVIRONMENTAL STATEMENT

VOLUME 2 OF 2

PROPOSED
INCREASE IN ACREAGE TO BE OFFERED
FOR OIL AND GAS LEASING
ON THE OUTER CONTINENTAL SHELF

DES 74-90

Prepared by the
BUREAU OF LAND MANAGEMENT

U.S. DEPARTMENT OF THE INTERIOR
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3. Pacific Region (and Sub-Areas)

a. Geology

The geology of the nearshore and coastal zone has been described in the discussion of the offshore environment (section II A 3 a). This was done to present a complete and continuous description. Unlike biological and some physical parameters, geologic structures are not commonly distinguished according to an arbitrary division based on water depth or proximity to the shoreline. Where specific geologic structures are unique to a nearshore area, they are noted as such.

b. Biological Environment and Communities of the Coastal Zone

This section will be divided into the following sub-headings: (1) terrestrial communities, (2) intertidal, and (3) bays and estuaries.

(1) Terrestrial Communities

The terrestrial areas of the coastal zone can be sub-divided into three major communities or biomes. The vast majority of the coastal zone south of Point Conception, California is urbanized and has lost its natural vegetative community structure. Grassland biomes are present but rare around Point Conception, Morro Bay, and Point Reyes, California. The woodland-bushland biome occupies the remaining non-urbanized coastal area of California south of Sonoma County. Continuing to the Canadian Border, nearly all the remaining coastal area consists of a coniferous forest biome (U.S. Dept. of Interior, 1973).

Because the woodland-bushland biome is so widespread, a wide variety of vegetation and wildlife occurs. However, no one species is unique to any one vegetation type or representative of the biome. The dominant mammal of the biome is the deer. The California mule deer is found near the coast in Santa Barbara and Ventura Counties, California. The blacktailed deer is common throughout the remainder of the area.

Some common large mammals of California's woodland-bushlands are the cougar, black bear and coyote. Smaller mammals are the gray fox, spotted and striped skunks, bobcat, jack rabbit, California ground squirrel, pocket gopher, raccoon, gray squirrel, and opossum.

There are many birds including several species of hawks, vultures, quail, pigeons, jays, magpies, and owls. The western fence lizard and rattlesnake are the most common reptiles. Nearly all of the streams which have perennial water support populations of trout or warm water game fish (U.S. Dept. of Interior, 1973). The animals of the grassland biome are the same species which occur in the woodland-bushland biome except that there are fewer deer and no black bears or cougar. Another exception is a greater variety of rodents and burrowing animals.

The most extensive biome along the Pacific coast (north of San Francisco) is that of the coniferous forest. At the more southern part of the biome animals are similar to those in the woodland-bushland biome. Additional mammals in the northern part are Roosevelt elk, martin, fisher, flying squirrel, mountain beaver and the red tree mouse. Some common birds are the blue grouse, horned owl, spotted owl, and sharp shinned hawk. The most common reptiles are the western fence lizard and several species of garter snakes.

There are relatively few species of fish in this area, but nearly all of the streams of any size have good populations of anadromous fish such as the steelhead, silver and chinook salmon. Farther norther other mammals such as the black bear, river otter, bobcat and mountain lion become more prevalent.

(2) Intertidal

(a) Rocky Shores

Areas having rocky shores or rocky outcrops on otherwise sandy beaches have a larger and more diverse intertidal community than sandy beaches. The total area comprising the rocky intertidal habitat varies seasonally. The heavy surf during the winter greatly increases the amount of rocky shores as it washes much of the sand away from the beaches. The movement of sand is important to the state of the rocky intertidal community. It can smother existing intertidal organisms, interfere with spawning and larval activities, and change the amount of available rocky shore. The relative duration of tidal exposure is another important aspect of the rocky shore intertidal community. Because of the degree of tidal exposure, the community may change over a vertical distance of only several feet.

Another important ecological factor on a rocky shore intertidal community is the degree of wave shock. With increased wave force the difficulty of an organism to hold on to the substrate or otherwise maintain its position increases. The degree of wave shock can also modify the vertical zonation pattern of a semi-protected area and alter the species composition of the community. This zonation tends to spread wider and higher in the regions of heavier wave action, often seen on coasts exposed to the main direction of the waves. Conversely, in very sheltered regions the whole zonal pattern may be so compressed that the uppermost zone is actually below the highest water mark of the year. The generalized zonal pattern described here is essentially a summary of observations of a semi-protected coastal situation.

Along the surf-swept open coast, the rocky cliffs of the Pacific have developed associations of animals with extreme staying power and resistance to wave shock. Furthermore, these animals apparently will not live elsewhere. These conditions have produced tough skins and heavy shells, strong tube feet of seastars, and the horny threads of natural plastic by which mussels are attached.

The force of the waves on stretches of completely open coast is so great that animals up near the high-tide line are wetted by spray on all but the lowest tides. Consequently, there is a widespread zonation and some of the most obvious animals are fairly well distributed throughout the intertidal zone.

Ricketts, Calvin, and Hedgpeth (1968) described the vertical zones of the intertidal exposure and habitats within them. These descriptions are applied to rocky shores in general.

1. Spray zone - This is a bare rock area in the main, but sometimes there are sparse growths of green algae. It is inhabited by hardy, semi-terrestrial animals, such as snails.
2. High tide zone - In this belt there is a greater variety of species and a tremendously greater number of individuals than in the spray zone. Some semi-permanent tide pools, with their active fauna of hermit crabs, snails, rock crabs, and barnacles occur here also. Plants appear in the uppermost part of this zone and grow lush in its lower part. These plants not only provide bases of attachment and protection from desiccation for sessile animals but furnish shelter for others that adhere to the rock.
3. Mid-tide zone - This area is largely uncovered by most low tides and covered by most high tides. The higher zones (spray and high-tide) seem relatively barren by comparison with the teeming life of this zone which is exceeded in density only by that of outer tidelands. Plants grow here in great profusion. These plants are of importance to the animals by providing protection from excessive solar heat and drying. The variety of animals associated in this zone is so great that it is possible to further divide the habitat as exposed rock, protected rock, underrock, burrowing, pool, root and holdfast.

4. Low-tide zone - Many of the mid-zone animals occur here too, but much of the population consists of animals unable to exist higher up and not accustomed to the rhythm of the tides. This crowded environment contributes a greater number of species than all the other tidal levels. In this zone, very few animals are exposed to wave action, sun, and wind on unprotected rock faces, except on open coasts where the surf is high. The habitat divisions of rock, under rock, burrowing, etc., are also present at the low-tide zone.

   The species composition of the attached algae changes with the latitude and temperature of the Pacific coast (Ricketts, Calvin and Hedgpeth, 1968; Allan Hancock Foundation, 1965). Each geographic region has similarly adapted species, typically of the same genus. The assemblage of *Mytilus californianus* (mussel), *Pollicipes polymerus* (stalked barnacle) and *Pisaster ochraceus* (ocher seastar) is characteristic of exposed beaches. On semi-protected beaches the mussel *M. edulis* is characteristic.

The extent and distribution of rocky shores on the Pacific coast is summarized as follows. South of Point Conception, California about 20% of the shoreline is rocky shore. North of this point, there is an increase in the amount of coastline having rocky shores. Monterey and Sonoma Counties have over 75% rocky shores. In Humboldt and

Del Norte Counties the relative amount of rocky shores decreases to 30 to 40% (California Dept. of Fish and Game, 1973).

According to the U.S.A Corps of Engineers (1971) southern Oregon has approximately the same amount of rocky shores as northern California (30 or 40%) for the first 50 miles of coastline. Proceeding northward, with the exception of an extensive rocky shore around Otter Rock in Lincoln County, rocky shores are rare, comprising less than 10% of the shoreline. This holds true for the Washington coastline except the extensive rocky coast around Cape Flattery near the Strait of Juan de Fuca. Much of the Oregon and Washington coastline is backed by sea cliffs, however, and many of the short pocket sandy beaches are transformed into rocky areas during the winter.

(b) Sandy Beaches

The coastal areas consisting of sandy beaches is the converse of that consisting of rocky shores. Although not as dynamic or as picturesque as rocky shores (and less well studied) sandy beaches form an important habitat for a community consisting of a surprising number of organisms.

The sandy beach is a rigorous environment because of the impact and continuous reworking by wave action. The main food supply for beaches is that of kelp and other algae and plankton washed ashore and buried in the sand or suspended in the surf. Animals of the beach are nearly all able to bore into sand rapidly. The number of species on sand beaches is considerably fewer than occur on rocky shorelines. The dominant species include: Orchestoidea californiana (sand hopper, an amphipod crustacean); Emerita analoga (sand crab); Donax gouldii (surf clam); Tivela stultorum (Pismo clam).

The grunion Leuresthes tenuis (a fish) utilizes sandy beaches for spawning during night-time spring tides between March and August. The female digs a hole and lays her eggs which are immediately fertilized by the male and left to incubate in the warm sand for two weeks. They are re-exposed and hatched at the next spring tide. These fishes occur only in Southern California and northern Baja California (Emery, 1960).

Increasing in importance in the Pacific Northwest (also present in parts of California) are butter clams, littlenecks, manila, cockles, geoducks, and horseclams. The most numerous northern clams are razor clams (Siliqua patula) (Washington Dept. of Natural Resources, 1972).

(3) Bays and Estuaries

Largely reflecting the gradual northward increase in rainfall and consequent river discharge volume in northern latitudes there is a general trend for the size of estuaries and their importance to the coastal marine environment to increase. Many of the small bays in southern California are fed by intermittent streams and actually lose free communication with the ocean during the summer dry period. In contrast to this is the Columbia River Estuary with a fresh water flow of from 15,000 to 600,000 cu. ft./sec. (Neal, 1972) which lowers the ocean salinity for a distance over 100 miles from shore (Barnes, et al, 1972).

There are exceptions to the above generalization regarding the size of estuaries. The nearly 14,500 acre San Diego Bay, though of substantial size, has lost most of its wildlife habitat through construction activity. The loss of natural estuarine areas is widespread in this country, but is particularly extensive in Southern California. According to the U.S. Fish and Wildlife Service (1972), at the beginning of this century there were 28 sizeable estuaries between Morro Bay, California, and Ensenada, Mexico. Since that time 15 have been modified either slightly or moderately, 10 have been altered drastically, and 3 have been destroyed.

California's coastal wetland and estuarine acreage is about 422,000 acres--less than one-half of one percent of the State's land area. Only about 31,700 acres of this is in Southern California, from Morro Bay south to the Mexican border. This is just 25% of that which existed in 1900. Less than 13,100 acres are marshlands and tidelands. The remaining 18,500 acres are open water.

San Francisco Bay, the largest estuary in California, remains the center of estuarine fishing activities for the State (Frey, 1971) in spite of its grossly polluted and altered condition, as studies by Filiece (1954, 1959) have demonstrated.

California estuaries are important to the life cycle of many important fishes, and are the habitat of the following sport and commercial shellfish: ghost shrimp, littleneck clam, gaper clam, Washington clam, oysters, bay shrimp, and market (Dungeness) crab (Frey, 1971).

Oregon has about 14 estuaries, the largest of which are the Columbia River Estuary (15,000 acres), Coos Bay (9,543 acres), Tillamook Bay (8,839 acres) and Umpqua-Winchester Bay (5,712 acres) (Oregon State Univ. Advisory Program). Washington, counting the Columbia River Estuary which is shared in common with Oregon, has the largest estuaries on the Pacific Coast. The most important are Willapa Bay (34,871 acres), Grays Harbor (7,150 acres) and the gigantic Puget Sound (about 1.3 million acres).

Fishery resources of Washington and Oregon estuaries include salmon, clams (gaper, cockle, softshell, butter and littleneck), oysters, and several species of shrimp and crabs. As with California, there are fin fish taken in the estuaries which also inhabit the oceanic areas.

The importance of estuaries as nursery areas and as nutrient and organic contributors to the oceanic coastline is obvious and will not be elaborated here.

(4) Commercial Fisheries

Because of the method of handling catch data according to State or region it is most convenient to divide the commercial fisheries discussion of the Pacific Coast into California and the Pacific northwest (Washington and Oregon). References for the California portion of this report came from Leet and Cramer (1971) and Frey (1971) while that of the Pacific northwest came from Glude (1971).

CALIFORNIA

The largest fishery of California-based fishermen is tuna. The port of San Pedro has been the Nation's leading port in terms of the value of landings (and until recently, total poundage) for over 20 years. These large landings are rather misleading, however, because over 80% of the tuna caught are landed outside California waters off Mexico and even further south. Bluefin tuna and albacore are the main tuna caught in California waters during their summer migrations into the area. The principal harvesting method of the pelagic species of tuna (except albacore) is purse seining. Tuna are almost exclusively canned. (Other species of fish are also canned, but unlike the tuna, are canned before being cooked.)

In addition to the summer tuna migrants mentioned above, pelagic fisheries include jack and Pacific mackerels, anchovy, sardine and squid. As the northern part of California is reached Pacific herring become more important.

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California may be an illustration of the depletion of ocean fishery resources due to over-fishing, although this is still subject to debate. Until the late 1940's the Pacific sardine was an extremely important fishery in the California Current. After this time its population, and therefore its landings, decreased drastically and the sardine catch was replaced by the anchovy catch. Surface current variation and water temperature change may have also contributed to the sardine population decrease. The Pacific mackerel is another species which has apparently been depleted by overfishing.

The bottomfish fishery is less well developed from Santa Monica Bay and further south than in the central part of the State and further north. Rockfish are the principal fish taken in these southern regions, but not with otter trawl nets. The principal species taken by otter trawl in central and northern California are flatfishes, rockfishes, sablefish, lingcod, and hake.

The salmon fishery is also best developed in the central and northern part of the State. The chinook or king salmon usually accounts for the vast majority of the catch. River fishing for salmon was discontinued in 1957 and the California fishery now consists of trolling in the ocean.

The principal shellfisheries are crabs, shrimp, spiny lobsters, abalone, and oysters. The market or Dungeness crab fishery is centered in the San Francisco and Eureka area while the relatively new rock crab fishery is centered in the southern part of the State. Bay shrimp and the recent ocean shrimp fishery are best developed in central California. The central California oyster fishery is strictly taken from artificial cultures and consists almost exclusively of the imported Pacific oyster.

Abalone and spiny lobster are best developed in the southern and central part of the State. The lobsters are taken by pots and traps while abalone are taken commercially by divers using hardhat or scuba gear.

Kelp harvesting is also an important marine resource in southern California. The harvest of around 100,000 tons annually is used for very large number of products including iodine, livestock feed, and algin products (used in ice cream, cosmetics, salad dressings, rubber, adhesives, etc.).

NORTHWEST PACIFIC

The relatively narrow continental shelf and large inland bays, especially Puget Sound and the mouth of the Columbia River, have resulted in large fisheries for salmon and bay fisheries on the northwest Pacific coast. Present-day fisheries have become more diversified both with respect to species caught and area fished. Part of the diversification has been necessitated because overfishing by U.S. fishermen and, more recently, foreign fisheries have decreased the stocks of the more popular species.

Historically the majority of fish caught in the Pacific northwest have been shipped to major population centers in California or the midwest. With the increasing population in this area recently, however, this tendency is decreasing as the region is utilizing more of its catch. The value of Pacific northwest fishing products is about 10% of the total value of U.S. fishing products.

Major fishery species include salmon (chinook or king and coho or silver), many of which are caught near the mouth of the Columbia River by gill netting and purse seining. Bottom fishes, such as flatfishes, rockfishes (including Pacific ocean perch), Pacific cod, and Pacific hake are taken principally by otter trawl. Most trawlers work in comparatively shallow waters of 20 to 180 meters. Halibut are caught with longlines.

Pelagic fisheries of the Pacific northwest include albacore tuna (during their summer migration into the area), Pacific herring, and northern anchovy. Only albacore and herring have been landed in large quantities. Albacore are generally caught by trolling lines using surface jigs. Herring are generally caught in bays and coastal waters with purse seines, weirs, gill and dip nets. No commercial fishery for anchovy has developed even though they are abundant off the Washington and Oregon coasts during the winter.

Shellfish include the native (Olympia) and larger Pacific oysters, essentially raised by mariculture, and several species of clams (more important as a recreation fishery than a commercial fishery). The most important clams of the area are the razor clam, butter clam, native littleneck clam, and manila clam, introduced from Japan.

Crustacens taken commercially in the Pacific northwest are mainly Dungeness (market) crab and pink Pandalid shrimp. Most crabs are caught commercially in pots or traps at depths between 4 and 45 meters. Pink shrimp are found on the continental shelf in depths of 75 to 180 meters, the most productive grounds being off northern California and southern Oregon. They are harvested with small otter trawls similar to those used in the Gulf of Mexico.

c. Resources of the Coastal Zone

(1) Land Use

The purpose of this section is to explore the land uses along the Pacific Coast. The reason for analyzing the form and structure of the uses are many. First an analysis reveals the existing relationship between land use activities and the transportation system. Second, an analysis forms the basis from which future population, employment, income, and transportation system can be forecasted by use of model systems.

Land use knowledge is also important in that patterns for expansion can be identified from past activities. Existing uses also represent areas that future growth must work around or alter if the need arises.

This report will present the land use for the southern portion of California, the central and northern portions of the state, and the coastal uses along the Oregon and Washington coast.

Southern California

Land use in southern California reflects the settlement patterns of economy of early days. Initially the area offered flat productive land for agriculture investments. The land resource, in addition to the favorable growing climate, made the area more attractive than the lands in the northern portion of the state.

California differed from the rest of the nation in that it did not have a large rural population. Because of climate and terrain the agricultural sector relied on irrigation for crop production. Since capital costs were high for irrigation systems there were not any great number of family oriented farms. As a result, the agriculture became a technologically intensive and labor extensive economy. This forced the incoming population to move directly to the coastal areas in search of other types of employment. This reason is true for other parts of the state as well.

After World War II the character of land development changed throughout the United States because of the advent of the automobile which encouraged a pattern of sprawl. The cities in southern California reflect this event.

The four main counties in this section include San Diego, Orange, Los Angeles, and Ventura. Large urban centers are located along the coast. These are the San Diego urban area, the Orange County-Los Angeles County urban area, and the Oxnard-Ventura complex which reaches into Santa Barbara. There is considerable ribbon type urban development in between the clusters which accounts for the ribbon city concept.

The eight Channel Islands, ranging in magnitude of size also reflects the land resource of the area. Development is limited to Catalina Island with agriculture, vacant, and military uses found on the other islands.

The main urban areas reflect the absence of a mass transportation system in that travel has become reliant on the automobile. The transportation network, which is characterized by many crossing freeways, highways, and surface streets provides the form and structure of the development. This is particularly true in the general Los Angeles area.

Topography has also served an important function in the development of urban life. Towns and cities developed in the flat areas and, in most cases, left the higher lands in a natural state. This is true today where the urban cores are located in the valleys and basins with the mountain left in a fairly natural state. Agricultural uses are also prominant in the coastal valleys, particularly in Ventura County.

The land use on the shoreline for the four counties and the islands is as follows:

Use	Miles
Public Recreation	141.5
Private Recreation	48.0
Nonrecreation Development	48.4
Undeveloped	299.2

Military uses in the area are mainly centered in the San Diego area ranging from Ream Naval Air Station in San Ysidro to Camp Pendleton at Oceanside. The San Diego Harbor area houses several naval and marine facilities with the majority found inside the harbor. There are several air stations located within the coastal zone.

The San Pedro harbor area in Los Angeles is the center of military uses there. The naval station at Long Beach and Ft. Mac Arthur are the largest facilities with a small site at Seal Beach.

The Port Hueneme - Pt. Mugu area in Ventura County is the center of naval and missile activities. The facilities are on the coast and are considered major uses in the area.

Central California

This portion of California includes the counties of Santa Barbara, San Luis Obispo, Monterey, Santa Cruz, San Mateo, and San Francisco. The majority of the development in the southern portion is in the vicinity of Santa Barbara which is closely allied economically and socially with the southern California area. That part of Santa Barbara County reflects the development constraits of the topography where growth is found along the shoreline. The same constraint is noticable throughout the coastal part of the county with the exception of Santa Maria, and the Lompoc areas where development occured in the wide alluvial vallies.

The closeness of the coastal range of mountains to the Pacific Ocean continues north to the Monterey Bay before any major valley areas occur. As a result, development is very limited with agriculture and forest representing the major land uses with a few scattered coastal towns and valley cities. With the exception of San Francisco County, the Monterey Bay region, and the urban centers in San Luis Obispo County the total stretch of the coastline is rural in nature.

The major urban development is centered in the San Francisco Bay area which is inland from the coastal zone. The topography is such is that development has occurred along the shoreline of San Francisco

County at the entrance to the Bay.

The land use on the shore line for the central California counties is as follows:

Use	Miles
Public Recreation	77.4
Private Recreation	47.7
Nonrecreation Development	9.6
Undeveloped	325.1

The above breakdown indicates the rural nature of the coastline. The public recreation areas are comprised of beaches and the nonrecreation development represents the urban areas. The small number of miles in that category and the large number of undeveloped miles generally represents the rural character of the coastline. No figures are given for the development within the San Francisco Bay region since the uses extends many miles inland and are located in several noncoastal counties.

The military uses in the southern portion include the Vandenberg Air Force Base in San Luis Obispo County, Fort Ord in Monterey County, and the Fort Funston and Presidio Military Reservation in San Francisco County. There are many military facilities in the San Francisco Bay region.

Northern California

The portion of the state north of San Francisco Bay includes Marin, Sonoma, Mendincino, Humbolt, and Del Norte Counties. The coastal range extends along the total length of the coast in close

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proximity to the Pacific Coast thereby limiting development.

The land use can be categorized as undeveloped forest lands interspersed with pockets of small urban areas. The largest city is Eureka in Humbolt County.

The rural nature of the stretch of coastline is emphasized by the following use breakdown:

Use	Miles
Public Recreation	154.9
Private Recreation	64.5
Nonrecreation Development	.2
Undeveloped	227.9

The public recreation group includes all the beaches and parks situated in the scenic areas of the coastline. The large amount of miles of undeveloped lands is a result of the hostility of the terrain which prohibits any large scale development to occur. The .2 miles of nonrecreation development represents a small amount of urban development, but does not reflect the towns which are built on the bays.

The only coastline military uses are found in Marin County on the San Francisco Bay. The complex of Fort Cronkhite, Fort Barry, and Fort Baker Military Reservations are clustered in the vicinity of the Golden Gate Bridge.

Oregon

The Oregon coastline is an extension of the physical features from northern California which results in a narrow strip of land between the Pacific Ocean and the Coast Range. As a result, the land use is not varied greatly and is represented by undeveloped forest lands, small farming areas, and small coastal towns. At the northern most point at the entrance to the Columbia River, Astoria has developed at the site of the natural harbor.

In general, the coastal zone is undeveloped and is characterized by the presence of cliffs and mountains which caused development to occur east of the mountains. The undeveloped nature of the coastal strip is observed by the total use of the coastline.

Use	Miles
Public Recreation	205.2
Private Recreation	81.3
Nonrecreational Development	110.0
Undeveloped	103.5

The policy of the State of Oregon towards recreation is noted in the 205 miles used in that category. The coastline is dotted with sites ranging from beaches to parks and historical sites. The amount of nonrecreational development includes the small towns, the tourist oriented strip commercial, and the lands used for service industries. Timber related activities are also prevelant together with farm uses.

The breakdown by county land use is:

County	Public Recreation	Private Rec.	Non Rec. Dev.	Undeveloped
Clatsop	27.0	3.5	22.0	6.5
Tillamook	42.0	1.0	36.0	32.0
Lincoln	24.5	24.0	29.5	10.0
Lane	17.0	11.0	0.5	11.5
Douglas	22.0	1.5	1.5	8.0
Coos	31.5	21.0	16.5	6.5
Curry	41.2	19.3	4.0	29.0

The only military uses on the coastline are the several coastguard stations and lighthouses. Fort Stevens by Astoria is not in active service at this time. The National Guard has acquired a facility in the area of Fort Stevens in which drills are held.

Washington

The shoreline of Washington does not differ greatly from that of Oregon except that the broken shoreline and the presence of harbors permits some coastline development to occur. The Grays Harbor and Willipa Bay areas are examples of development centers. The Quinault Indian Reservation, although relatively undeveloped is located in Grays Harbor County.

No attempt has been made to determine the uses along the Strait of Juan de Fuca or in the Puget Sound, rather the following statistics will be limited to the coastal zone only. An exception is Clallam County where the statistics do include a portion of uses on the Strait of Juan de Fuca.

County	Public Recreation	Private Rec.	Non Rec. Devel.	Undeveloped
Clallam	8.9	0	6.0	141.1
Jefferson	15.6	2.2	2.0	174.2
Grays Harbor	29.0	8.1	8.0	100.9
Pacific	46.8	0	1.0	137.2

Similar to northern California and Oregon, the coastline of Washington is in a natural state. Because of topography the bulk of development in the state occured between the coastal range of mountains and the main central mountains. The pattern of the Puget Sound area is similar to the Willamette Valley development found in Oregon.

Summary

In general the land use of the Pacific Coast can be categorized as being land in its natural state with the exception of urban developments in the valley areas. The majority of development has taken place in Southern California with major urban pockets at San Francisco, Portland, and in the Straits of Juan de Fuca. The recreation potential has been protected in most cases and has been acquired and developed for public interest. The urban developments exist because of terrain and the existence of a transportation system. The lands in a natural state are generally classified as forest land or rocky cliffs in close vicinity to the beach. Farming is interspersed throughout the area.

(2) Recreation Resources

California

California's coast is its single most valuable natural resource. It provides food, transportation, medicine and raw materials, makes a major contribution to the environmental quality, satisfies many of the state's burgeoning recreation demands, and attracts tourists and out-of-state visitors. A large part of the state's recreation activity occurs at the beaches.

The southern coastal area contains major portions of California's people and coastal development. Most of the state's sandy beaches and its warm waters are in southern California adjacent to this megalopolitan center. Waters warm enough to encourage water contact sports such as swimming occur only in the Santa Cruz area of northern California and south of Point Conception in southern California.

Visitors to the shore fish, swim, beachcomb, camp, picnic, hike, surf, skin and SCUBA dive, photograph, paint, water ski, sunbathe, or just relax. More than 127 million recreation days were spent at the shore during 1970, an increase of 5 million days over 1969. In addition, many hundreds of thousands of visitors were turned away due to crowding.

A highly efficient personal transportation system exists in southern California and provides access to recreation areas.

Inland, the mountains of the San Gabriel, San Bernardino and Cleveland National Forests provide open space, hiking, camping, winter sports and numerous other recreation values. Farther north and east, the vast reaches of the Mojave and other deserts swarm with recreationists.

Urban recreation demand is the most prominent feature of California's recreation problems. The state's population is largely urban and concentrated near the coast. More than 90% of the outdoor recreation demand in California is generated by the metropolitan population (CORRP 1972). Forty-one percent of recreation use occurs within one hour's travel of the urban complex. In urban impacted areas, 44% of the families do not own or have use of a car, and satisfy recreation demands very close to home. Such factors as the Southern California Rapid Transit District experiment in the use of special buses for transportation to and from the beaches may affect this demand mix.

In-migration has slowed for California and for Los Angeles particularly. However, recreation demands on California's beaches will continue to grow. The California Department of Parks and Recreation, in A Study of Future Beach Use, concluded:

> In the next fifty years, California beaches will become more and more crowded because: (1) the population will increase; (2) large portions of the population will have more of both money and leisure time; and, (3) improved transportation methods will bring larger numbers of people to the beach more rapidly and from greater distances. In answer to this crowded demand, new recreation equipment aimed at the underwater space along the shore will be marketed. (Hinshew, 1970)

National Park Service

Four areas are administered by the NPS within California's coastal zone. These include Redwood National Park, Point Reyes National Seashore, Cabrillo and Channel Islands National Monuments.

National Registry of Natural Landmarks

(Cal. Regional Comprehensive Framework Study. Appx XII, 1971)

The National Park Service, under the authority of the Historic Sites Act (Public Law 74-292, August 27, 1935) gives recognition and consultative assistance to conservation efforts in natural areas by dedicating them as Registered Natural Landmarks. This program does not involve financial support or changes in land ownership and does not guarantee protection and preservation of landmarks. Existing and potential natural landmarks in the coastal California area include the following:

1. Big Lagoon, Humboldt County-NPS, Humboldt County, Private
2. Audubon Canyon Ranch, Marin County- Audubon Canyon Ranch Inc.
3. Golden Gate Headlands, Marin County - Dept. of Defense and Gulf Oil Company
4. Elder Creek, Mendocino County - BLM
5. Pygmy Forest, Mendocino County - State
6. Ventana Creek Canyon, Monterey County - Forest Service
7. Pacific Grove (Monarch Butterfly), Monterey County - Private
8. Point Lobos, Monterey County - State
9. Buena Vista Lagoon State Park, San Diego County - State and Private
10. Torrey Pines Reserve, San Diego County - State
11. Nipomo Dunes Natural Area, San Luis Obispo County - BLM and PG&E
12. Shell Creek Natural Area, San Luis Obispo County
13. Goat Island, Mendocino County - BLM
14. La Jolla Underwater Site, San Diego County - University of California

Wild, Scenic and Recreational Rivers

The following streams or portions thereof are identified as being of sufficient quality to warrant study for possible inclusion under the Wild and Scenic Rivers Act, PL. 90-542. Those marked with an asterisk are included under section 5(d) of the Act.

Streams of National and Regional Significance

*1. Klamath River - source to ocean
2. Main Stem Trinity River
*3. Smith River - source to ocean
*4. Russian River - Ukiah to ocean
5. Gualala River - source to ocean
6. Navarro River - source to ocean
7. Main Stem Eel River
8. Redwood Creek

Stream of Regional Significance

1. San Lorenzo River

Coastline Ownership & Acquisition

The California Region has 1,073 miles of coast line but only 179 miles with sandy beaches, safe profiles and water temperatures suitable for swimming. Of these recreation beaches only half are now in public ownership. The privately-owned beaches are generally located near major metropolitan areas and are being relegated to uses other than recreation at a faster rate than other shoreline types. The California State Park System Plan recommends that the acquisition of swimming beaches be given first priority by the Department of Parks and Recreation.

Channel Islands

Relatively, undisturbed and close to one of the largest urban complexes in the Nation, the Channel Islands represent a great potential ecologic and recreation resource.

Located off the coast of Santa Barbara, Los Angeles, and San Diego are San Clemente, San Nicolas, Santa Catalina, Anacapa, Santa Rosa, Santa Cruz, San Miguel and Santa Barbara Islands, known collectively as the Channel Islands. At present, the Department of Defense administers San Clemente, San Nicolas and San Miguel Islands, while Santa Barbara and Anacapa Islands are within Channel Islands National Monument. San Miguel's surface resources are administered jointly by the Department of the Interior and Defense. Santa Cruz, Santa Rosa and Santa Catalina are privately-owned under single or large ownerships. Santa Catalina is the only island with urban development.

Periodically, legislation has been introduced in Congress to include Anacapa, Santa Rosa, Santa Cruz, San Miguel and Santa Barbara Islands in a new national park. These islands, comprising about 133,000 acres, offer fine opportunities to preserve seashore values and provide a remarkable variety of recreation opportunities for the metropolitan south coastal area. The islands contain unique plant and animal life resulting from a half million year of isolation from the mainland, extraordinary marine fauna, great rookeries of nesting birds, and a museum of geological structures and processes.

At present, the primary limitation on use of the islands is a combination of distance, rough waters and private ownership. The two islands in national monument status (Anacapa and Santa Barbara) are not developed, although two primitive campgrounds exist and SCUBA divers use of the surrounding waters which are included in the national monument for a distance of one nautical mile from shore. Few protected anchorages and good boat landings and very little possible water exist on any of the islands.

Oregon

Oregon has 500 miles of shoreline comprising 352 miles along the Pacific Ocean and 148 along the 15 estuaries inventoried. Of Oregon's 500 miles of shoreline, 300 miles have beach and 200 miles are without beach, consisting of rocky headlands, marsh areas, bulkheads and revetments.

The central coast area is famous for its large, active sand dunes, some rising to heights of 250 feet or greater. South of Coos Bay to Cape Blanco, the shoreline consists of low cliffs and narrow sand beaches dominated by marine terraces. There are no rock headlands except at Cape Arago, Bandon, and Cape Blanco. Coos Bay and the Coquille River estuary are the only significant embayments in the region. Cliffs and small bays characterize the rugged shoreline south of Cape Blanco. The narrow bay-head beaches are composed of coarse sands and gravels.

Most of the Oregon coast is bordered by mountains, with the Oregon coast range extending along the northern portion and the Klamath Mountains along approximately the southern 70 miles. U. S. Highway 101, the Pacific Coast Highway, extends north and south through the State, generally paralleling the ocean-vegetation consists of beach grass, brush and trees. Trees generally grow close to the shore only on rocky bluffs and headlands where they are wind pruned into picturesque shapes.

Between the towns of Florence and Reedsport are several freshwater lakes just inland of the sea. The largest of these are popular resourt and fishing areas.

Ownership

A small amount of the upland adjacent to the line of ordinary high water in Oregon is owned by the Federal Government. The remainder is divided between State and local agencies and private individuals. Approximately 83 miles are Federally owned, 158 miles are owned by non-Federal public bodies, and 238 miles are privately owned. Ownership of the remaining 20 miles is uncertain.

The Oregon State Legislature has recognized that over the years the public has made frequent and uninterrupted use of lands abutting the shore of the Pacific Ocean, seaward of the natural vegetation line, for recreational purposes and that such use has been sufficient to create easements for the public through dedication, prescription, grant, or otherwise. Accordingly, the Legislative Assembly declared it to be in the public interest to protect and preserve public easement acquired through dedication, prescription, grant, or otherwise as a permanent part of Oregon's public recreational resources and to recognize and protect the rights of private owners to those lands that are not subject to public easements (ORS 390.605 et seq.). This legislation is commonly known as the "Beach Bill." The State

Highway Commission has been delegated the authority to protect and preserve the rights of the public in the lands described in the Act.

Recreation Use

Oregon beaches have long attracted both the people living on the coastal strip as well as those living in the populous Willamatte Valley. Lesser centers such as Roseburg, Grants Pass and Medford also contribute much recreation pressure at the coastline. The Oregon coast also attracts vacationers from California. The heavy tourist influx has created a strip type of recreational development along some portions of Highway 101.

This development along Oregon's coast has for the most part been recreational in nature. The municipalities are generally oriented towards the tourist industry with resort-type development for the summer visitor. About one-fifth of Oregon shore has not been developed in any true sense, and much of the area listed herein as private recreational areas has little formal development. Notwithstanding the lack of development, where beaches exist and are accessible, the public has made use of the area for recreation--hiking, beachcombing, "cookouts," etc. That long historic usage

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is reflected in the legislation cited earlier. Along the Oregon-coast, there are approximately 60 parks and recreational areas developed by Federal and State agencies, by individual counties, and by private power and timber companies. There are approximately 200 miles of shoreline which have been developed to some degree for public recreation. Of the remainder, about 80 miles are private recreation areas, 110 miles are developed for nonrecreational purposes, and 100 miles are undeveloped.

Residential development, both for summer occupancy and year-round use, is increasing. Many retired people, attracted by the moderate climate, are moving into coastal areas. Future development is expected to continue along much the same lines as in the past; however, increased residential development for year-round use and also some light industry may be expected.

Data gathered for 1968 and including attendance at State parks, forest camps, game units and marinas indicate visitors totalling 14,871,000. A breakdown of these figures appears in the following table.

Coastal Section	Visitors
North Coast	2,060,000
Tillamook Bay	582,000
Yaquina Bay	1,325,000
20 Miracle Miles	1,875,000
Alsea Bay	1,561,000
Siuslaw	1,598,000
Winchester Bay	1,236,000
Coos Bay	3,041,000
South Coast	1,593,000

Oregon Coastal Recreation visitors 1968

Source: Oregon State Highway Division - State Parks and Rec. Branch

The Oregon coast is a treasured and zealously guarded fragile resource. Coastal resources are in relatively good condition. With minor isolated exceptions, esthetic quality is excellent. Developmental infringement of the actual shore zone is rare. Coastal physiographic and natural features contribute immensely to scenic variety, interest and quality.

Recreationists use the coast for hiking, camping, picnicking, fishing, clamming, crabbing, beachcombing, photography, SCUBA diving and sightseeing. Sport fishing both by charter boats and private craft is popular for salmon. Observation of wildlife contributes significantly to recreational enjoyment. Tidepool animals are seriously threatened in many areas due to casual collecting.

Anadromous fish runs occur in almost all of Oregons' coastal rivers. Sea-run cutthroat, two salmon species and steelhead are the most frequently caught species. Angler effort is concentrated in ocean areas near the stream mouths, on jetties and in the estuaries as well as up stream areas. All of the coastal rivers except the Coos Yaquina and Coquille rivers have heavy recreation use. The Rogue and Wilson Rivers have the biggest anadromous fisheries. The Rogue River is designated a Wild River under the Federal Wild and Scenic Rivers Act.

The unusually heave recreation demand relative to the region's population is caused by non-resident recreationists. The capacity of existing resources will likely be exceeded during this decade without further site development, especially overnight sites. Many State parks are on a reservation system presently.

Cold water and brisk cool breezes make swimming and sunbathing pursuits for the hardy few. The coast offers a very desired environment of sea and sand, sun, keening winds and ocean smells. Any alteration of this mix or crowding of the area depreciates the enjoyment it offers. The Comprehensive Framework Study (1971) identified the following as necessary to preserve Oregon's existing high quality coastal environment:

(1) maintaining and enlarging upon the existing scenic roads and highways (including adjacent scenic corridors of land); (2) dedicating the major portions of all 25 free-flowing rivers and segments, including adjacent scenic corridors; (3) building several small reservoirs in upper tributaries for recreation, fishing, and improving quantity and quality of downstream summer flows; (4) regional land-use zoning to insure that commercial developments and private recreation facilities are harmonious with surroundings and of the proper density; (5) improving the wildlife habitat on the Federal lands, the privately owned timber

lands, and ranch lands; (6) constructing and maintaining public and private high quality recreation facilities (including trails) to satisfy needs; (7) preserving existing primitive, historical, and archeological values, and (8) limiting the recreation use before it begins to cause deterioration in either the environment or the recreation experience. The latter situation is projected to begin about the year 2000. (Cal.-North Pac- Comp. Framework Study, Appx. XIII, 1971)

Washington

Two hundred miles of the Pacific Ocean wash Washington's green western coast. Rugged and wild, this scenic shoreline is one of the last untrammeled ocean beach areas in the Nation. No major highways closely parallel the coast and access to the beach is by "gap" roads which head out to the sand. Off-the-road vehicles (ORV's) make much use of the broad sandy beaches which occur along the shore. Long Beach boasts of the world's longest stretch of sandy beach; it reaches some 28 miles.

Public recreational use of about 140 miles of shoreline occurs in publicly owned parks and pleasure-boat moorage facilities. Private recreational facilities totaling 40 miles consist of resort areas and privately owned pleasure-boat moorage facilities. About 77 miles of shoreline have nonrecreational development such as commercial and industrial areas. Fishing, picnicking, hiking, camping, beachcombing and clamming are the most frequently engaged recreational pursuits.

Inclusive of Puget Sound and the Strait of Juan de Fuca, about 2,075 miles of Washington's shoreline landward of the extreme high waterline are in private ownership. The Federal Government owns about 155 miles including the Olympic National Park and various wildlife refuge areas. Non-Federal public ownership totals 107 miles, primarily State, county and city parks. Some of the non-Federal public land is owned by various port districts and utilized for waterborne commerce facilities and small-boat moorage facilities. The State of Washington owns or controls most of the land seaward of the extreme high waterline. The State has sold some of these lands near urban areas.

About 2,000 miles of the shoreline are currently undeveloped because of remoteness or because high banks make access difficult.

On the Olympic Peninsula, magnificent stands of coniferous rain forest trees grow in rampant profusion. Olympic National Park embraces the central mountain area of the peninsula and includes a long stretch of the coast. The remaining major portion of the north half of the coast is taken up by the Makah and Quinault Indian

Reservations. Reservation lands formerly open to public recreation, are presently closed.

Northwest Coast

The Pacific Ocean shoreline from Cape Flattery south to the Quinault River is quite rugged and rocky with high bluffs. The shoreline is interrupted with generally narrow beaches and small rivers. The adjacent uplands are heavily forested with trees extending to the beach's edge or to the top of bluffs. From the Quinault River south to the Washington-Oregon border the shoreline generally consists of flat straight sandy beaches with dunes and grasslands abutted by low banks gently sloping upland. Grays Harbor, Willapa Bay and the Columbia River are major estuaries along the reach. Neah Bay, lying just east of Cape Flattery in the straight of Juan de Fuca, provides a harbor for an Indian village, Coast Guard station and a large sportfishing fleet. Shoreline public parks between Cape Flattery and Moclips are: Ozette County Park, Washington Islands Wilderness, National Wildlife Refuge (rocks, reefs, islands, and islets) and Olympic National Park. There are no State parks along this shore area. There is a boat servicing facility at La Push near the mouth of the Quillayute River.

Underwater recreation occurs mainly at Neah Bay. Recreational crabbing is practiced along the northwest half of Clallum County coast, south half of Jefferson County, the north half and southern third of Grays Harbor County. Hardshell and razor clams are major recreational targets on the coast. Clams are found at scattered points along the southwest half of Clallum County, most of Jefferson County, at the mouth of the Raft River, and from the Quinault River southerly to Moclips (Washington State 1972). Steelhead runs also occur in many streams.

No rivers have been designated under the Federal Wild and Scenic Rivers Act, nor have any been identified for study. The following streams are prominent recreation rivers:

Soleduck River
Bogachiel River
Hoh River
Quillayute River

Potential development as well as roadless areas exist scattered along the coast.

Identified scenic routes extend from Highway 101 as it approaches the coast from the east where it parallels the Strait of Juan de Fuca, south to the Quinault Indian Reservation where 101 goes inland Highway 109 parallels the coast through the reservation to Grays Harbor where it extends inland to Aberdeen. It is an identified scenic route along the entire described length.

Much of recreation demand in Washington comes from the urban centers of King County (Seattle-Everett) and Pierce County (Tacoma). Development of sites, particularly for overnight use, is lagging behind demand.

Nearly 2 million visitors were recorded at the five Washington State Parks listed below for F.Y. 1973. Day use of ocean beaches for F.Y. 1973 was 940,000 for North Beach, 35,000 for South Beach and 1,782,000 for Long Beach areas (Washington State Parks and Recreation Comm. 1973).

Southwest Coast

There are several shoreside public parks and two National Wildlife Refuges within this reach of shoreline. South of Moclips are Pacific Beach and Ocean City State Parks. Two Fish and Game Department Recreation areas are located in Grays Harbor. There is also an underwater park for SCUBA divers at Fort Casey State Park on the south spit at Grays Harbor. Between Willapa Bay and Grays Harbor, there are three shoreline parks. Within Willapa Bay, there are numerous recreation facilities associated with State and Federal wildlife refuges. Additionally, there is one State and several county parks. Fort Canby State Park at Cape Disappointment completes the list.

TOTAL VISITORS TO WASHINGTON STATE SHORELINE PARKS, F.Y. 1973

PARK	VISITORS
Ocean City	360,000
Fort Canby	595,000
Westhaven	236,000
Fort Casey	455,000
Twin Harbors	280,000

Boating facilities or rendezvous areas are found at Copalis, on the coast, and in Grays Harbor and Willapa Bay. An important marina facility also exists at Ilwaco inside the Columbia River estuary.

Sportsmen take crab along the entire south coast and into Grays Harbor and Willapa Bays. Razor clams are also dug along this entire coast while hardshell clams are found in both Grays Harbor and Willapa Bay.

(3) Ports and Shipping

The major coastal transportation system along the Pacific Coast from Mexico to Canada is regional in nature in that it serves California, Oregon, and Washington and is located because of topographical features. The main route is Interstate 5 which runs the entire length of the state but serves the main urban centers. As a result, the facility does not serve the coastal zone. The Highway 101, or the coastal route, serves the entire length of the coast line. There are several state hiway connectors and local roads in each area which provide connecting east-west travel to the interior vallies.

Ports and Shipping

Shipping plays a major role in the economy of the West Coast because of the size and location of natural harbors which are sheltered from the sea. The ports extend the entire length of the coast from San Diego on the south to the several ports located in vicinity of the Puget Sound area in Washington. The importance is noted by the growth of activities for both imports and exports for Pacific ports since 1950. The U.S. Census indicates the growth in short ton activities as:

Year	Imports	Exports
1950	4,095	7,270
1955	9,038	13,394
1960	23,281	19,351
1965	29,995	26,445
1967	26,223	36,486
1968	28,292	39,146
1969	31,957	41,018
1970	30,846	47,518
1971	39,255	37,664

The information depicts the growth over the twenty one year period and indicates a sevenfold increase in just the commerical activities. The above figures do not reflect the movement of the fishing fleet, military vessels, tugs and barges, Pacific Coast internal traffic or the use of pleasure boats. The overall picture of all shipping does, however, indicate a major increase in shipping activities with an increase in tug usage and other ancillary type vessels.

The absence of designated ship traffic lanes is obvious along the West Coast. The official National Ocean Survey (NOS) Navigation maps for the Pacific Coast shows only two designated traffic lanes. The first runs northerly from Los Angeles through the Santa Barbara Channel, and the second is the approach network outside of the San Francisco Bay.

Shipping along the coast must be cognizant of two military related designations as shown on the NOS Navigation maps. The United States Navy has designated large areas as warning areas. Shipping is allowed in the zones under most conditions but the possibility exists that some restrictions can be placed in force under certain conditions. In some areas submarine lanes are reserved as shown on the NOS Navigation maps.

The San Diego Port in Southern California is formed by the natural harbor which shelters the bay from the ocean. The yearly tonnage shipped shipped in and out of the harbor has remained fairly constant over the past ten years, just under two million tons. In 1972 the figure was 1,666,283 tons which was represented by 237,236 tons of import goods and 252,739 tons classified as exports. The remainder was represented by domestic cargoes which included coastwise, internal, and local movements. In 1972 the inbound ship movements totaled 1,775 vessels including tugs and barges.

Shipping activities in Southern California are the greatest in the Los Angeles - Long Beach area. Both areas are governed by a separate port authority which reports on an individual basis.

The amount of tonnage has doubled for the Long Beach port from more than ten million tons in 1963 to over twenty million tons in

1972. During the same period the Los Angeles Port increased from twenty million tons to almost twenty four million tons. The volume of ship traffic is greater in the Los Angeles harbor due to the large amount of tugboats, tow boats, and non self propelled vessels coming in and leaving the harbor. In 1972, for example, almost 7,000 inbound vessels were recorded, of which 1,300 who represented by passenger, dry cargo, and tanker vessels.

In 1972 the Long Beach activity by tons was:

TOTAL	IMPORTS	EXPORTS	DOMESTIC
20,795,050	7,649,201	4,780,867	8,364,982

Of the total movement, about two thirds of all the activity was internationally oriented with the remainder classified as domestic.

The Los Angeles Port activity for the same year was:

TOTAL	IMPORTS	EXPORTS	DOMESTIC
23,836,690	7,973,893	3,032,189	10,830,608

The data indicates that just under half of all cargo handled is domestically shipped. The import and export volumes are similar to that recorded for the Long Beach facility.

There are other minor ports or harbors in Southern California which report shipping. The location and volume of tonnage are:

LOCATION	TONNAGE
Port Hueneme	173,110
Carpinteria	529,102
El Segundo	5,157,833
Encino	307,899
Estero Bay	4,026,962
Huntington Beach	298,775
San Luis Obispo	1,396,343
Ventura Harbor	2,353,120

In northern and central California, the large share of the vessel and cargo activity is located within the vast San Francisco Bay and in the individual port facilities of the various cities. Some of the traffic is also associated with river traffic in the area.

In terms of the Pacific Coast study, the traffic at the entrance to the San Francisco Bay is significant while the final destination once inside the harbor is not. The increase in tonnage at the entrance for a ten year period indicates a growth of just less than fifty percent. The yearly totals for all categories are:

YEAR	TONNAGE
1963	32,364,704
1964	31,107,292
1965	33,120,773
1966	33,576,485
1967	32,605,075
1968	35,670,970
1969	39,834,720
1970	39,650,439
1971	40,373,263
1972	44,560,899

The 1972 inbound traffic count was 4,622 vessels. Of the total 4,215 constituted passenger, dry cargo, and tanker vessels. The remainder was composed of towboats, tug boats, and non self propelled vessels. A large share of the passenger and dry cargo vessels had either San Francisco Harbor or the Oakland Harbor as their destination. Of the 1,306 tankers entering the bay, 758 sailed to Richmond Harbor to the Standard Oil Refinery.

The Coos Bay Harbor serves as an export facility for Southern Oregon. The amount of tonnage increased by almost double for the ten year period from 1963 to 1972. The total amount of tonnage by year was:

YEAR	TONNAGE
1963	3,233,465
1964	3,975,628
1965	4,115,031
1966	5,265,795
1967	3,949,169
1968	5,746,929
1969	6,101,771
1970	6,098,778
1971	6,747,507
1972	6,543,775

The tonnage types for 1972 indicates the exporting nature of the port and the high percentage of domestic vessel traffic.

TOTAL	IMPORTS	EXPORTS	DOMESTIC
6,543,775	438	3,861,062	2,682,275

Of the total, more than half of the tonnage was international in classification with approximately forty percent included in domestic traffic.

The bulk of shipping for Oregon is located in the vicinity of the Columbia River area. Similar to San Francisco Bay, the best indication of volume is that which passes through the mouth of the Columbia River since many vessels travel up the river to various destination points.

In 1972 there were 2,952 inbound vessels recorded entering the Columbia River from the Pacific Ocean. Of the total, 2,258 were classified as passenger, dry cargo, or tanker vessels. The bulk of vessels had a draft of twenty six feet or less.

The tonnage passing through the entrance of the Columbia River from 1963 to 1972, as recorded by the Corp of Engineers was:

1963	14,690,545
1964	14,779,190
1965	15,926,482
1966	16,123,351
1967	16,364,488
1968	16,786,264
1969	17,951,018
1970	19,541,780
1971	16,750,718
1972	20,282,863

The data indicates a one third increase in volume over the ten year period. Of the total traffic, a large share went to the ports in Astoria, Vancouver, and Portland. Other amounts continued to various destinations up the Columbia River.

Similar to the Coos Bay Harbor, the port at Grays Harbor, Washington can be classified as an export point. The volume of tonnage handled by the port increased by nearly one third from 1963 to 1972.

The amount by year was:

YEAR	TONNAGE
1963	2,218,812
1964	2,084,123
1965	2,387,908
1966	2,737,555
1967	2,512,533
1968	2,878,024
1969	3,491,965
1970	3,574,467
1971	2,753,320
1972	3,785,907

The figures are significant in that the tonnage handled is approximately three times greater than that recorded for the Port of San Diego.

The classification of freight traffic for 1972 was:

TOTAL	IMPORTS	EXPORTS	DOMESTIC
3,785,907	708	2,660,956	1,124,343

The amount of imports is very insignificant in relation to the two thirds of the total being exported and the one third shipped domestically.

A large amount of ship traffic enters and leaves the Pacific Ocean at the Strait of Juan de Fuca in Northern Washington. The shipping serves both the Puget Sound area and the Canadian ports to the north. Unfortunately the Corp of Engineers in their annual Waterborne Commerce reports do not provide the total vessel count at the entrance of the Strait of Juan de Fuca. As a result, the Canadian vessel count is not available at this time.

Some indication of vessel movement can be observed by the tonnage counts at various ports within the Puget Sound area. The port of Seattle, for example, reported a total of 14,662,811 short tons of cargo moved in 1972. Port Angeles moved 2,849,121 short tons, and Tacoma reported handling an additional 8,477,318 short tons of cargo.

In terms of vessel counts by ports, the facility at Port Angeles reported an inbound count of 2,224 for 1972. Tacoma for the same period reported 7,264 and Seattle accounted for 58,725 which included 15,075 towboats and tugboats.

The counts do not reflect many of the pleasure crafts or military vessels which are berthed at the Naval Stations. In terms of the intensity of traffic on the Pacific Ocean in the area, the military vessels must be acknowledged.

(4) Commercial Fisheries

Because of the method of handling catch data according to State or region it is most convenient to divide the commercial fisheries discussion of the Pacific Coast into California and the Pacific northwest (Washington and Oregon). References for the California portion of this report came from Leet and Cramer (1971) and Frey (1971) while that of the Pacific northwest came from Glude (1971).

CALIFORNIA

The largest fishery of California-based fishermen is tuna. The port of San Pedro has been the Nation's leading port in terms of the value of landings (and until recently, total poundage) for over 20 years. These large landings are rather misleading, however, because over 80% of the tuna caught are landed outside California waters off Mexico and even further south. Bluefin tuna and albacore are the main tuna caught in California waters during their summer migrations into the area. The principal harvesting method of the pelagic species of tuna (except albacore) is purse seining. Tuna are almost exclusively canned. (Other species of fish are also canned, but unlike the tuna, are canned before being cooked.)

In addition to the summer tuna migrants mentioned above, pelagic fisheries include jack and Pacific mackerels, anchovy, sardine and squid. As the northern part of California is reached Pacific herring become more important.

California may be an illustration of the depletion of ocean fishery resources due to over-fishing, although this is still subject to debate. Until the late 1940's the Pacific sardine was an extremely important fishery in the California Current. After this time its population, and therefore its landings, decreased drastically and the sardine catch was replaced by the anchovy catch. Surface current variation and water temperature change may have also contributed to the sardine population decrease. The Pacific mackerel is another species which has apparently been depleted by overfishing.

The bottomfish fishery is less well developed from Santa Monica Bay and further south than in the central part of the State and further north. Rockfish are the principal fish taken in these southern regions, but not with otter trawl nets. The principal species taken by otter trawl in central and northern California are flatfishes, rockfishes, sablefish, lingcod, and hake.

The salmon fishery is also best developed in the central and northern part of the State. The chinook or king salmon usually accounts for the vast majority of the catch. River fishing for salmon was discontinued in 1957 and the California fishery now consists of trolling in the ocean.

The principal shellfisheries are crabs, shrimp, spiny lobsters, abalone, and oysters. The market or Dungeness crab fishery is centered in the San Francisco and Eureka area while the relatively new rock crab fishery is centered in the southern part of the State. Bay shrimp and the recent ocean shrimp fishery are best developed in central California. The central California oyster fishery is strictly taken from artificial cultures and consists almost exclusively of the imported Pacific oyster.

Abalone and spiny lobster are best developed in the southern and central part of the State. The lobsters are taken by pots and traps while abalone are taken commercially by divers using hardhat or scuba gear.

Kelp harvesting is also an important marine resource in southern California. The harvest of around 100,000 tons annually is used for very large number of products including iodine, livestock feed, and algin products (used in ice cream, cosmetics, salad dressings, rubber, adhesives, etc.).

NORTHWEST PACIFIC

The relatively narrow continental shelf and large inland bays, especially Puget Sound and the mouth of the Columbia River, have resulted in large fisheries for salmon and bay fisheries on the northwest Pacific coast. Present-day fisheries have become more diversified both with respect to species caught and area fished. Part of the diversification has been necessitated because overfishing by U.S. fishermen and, more recently, foreign fisheries have decreased the stocks of the more popular species.

Historically the majority of fish caught in the Pacific northwest have been shipped to major population centers in California or the midwest. With the increasing population in this area recently, however, this tendency is decreasing as the region is utilizing more of its catch. The value of Pacific northwest fishing products is about 10% of the total value of U.S. fishing products.

Major fishery species include salmon (chinook or king and coho or silver), many of which are caught near the mouth of the Columbia River by gill netting and purse seining. Bottom fishes, such as flatfishes, rockfishes (including Pacific ocean perch), Pacific cod, and Pacific hake are taken principally by otter trawl. Most trawlers work in comparatively shallow waters of 20 to 180 meters. Halibut are caught with longlines.

Pelagic fisheries of the Pacific northwest include albacore tuna (during their summer migration into the area), Pacific herring, and northern anchovy. Only albacore and herring have been landed in large quantities. Albacore are generally caught by trolling lines using surface jigs. Herring are generally caught in bays and coastal waters with purse seines, weirs, gill and dip nets. No commercial fishery for anchovy has developed even though they are abundant off the Washington and Oregon coasts during the winter.

Shellfish include the native (Olympia) and larger Pacific oysters, essentially raised by mariculture, and several species of clams (more important as a recreation fishery than a commercial fishery). The most important clams of the area are the razor clam, butter clam, native littleneck clam, and manila clam, introduced from Japan.

Crustacens taken commercially in the Pacific northwest are mainly Dungeness (market) crab and pink Pandalid shrimp. Most crabs are caught commercially in pots or traps at depths between 4 and 45 meters. Pink shrimp are found on the continental shelf in depths of 75 to 180 meters, the most productive grounds being off northern California and southern Oregon. They are harvested with small otter trawls similar to those used in the Gulf of Mexico.

(5) Oil and Gas Resources

The following estimates of oil and gas resources are provided by U.S. Geological Survey. USGS emphasizes that the estimates are speculative; only the maximum credible expectations are shown.

TABLE A. Measured and Inferred Reserves, 0-200 meter water depth. (12-31-72)
(Oil in billions of barrels and includes natural gas liquids)
(Gas in trillions of cubic feet)

Area	Measured Reserves Oil	Measured Reserves Gas	Inferred Reserves Oil	Inferred Reserves Gas
Southern California Santa Barbara	3	3	1-2.5	1-2.5
Northern California	0	0	0	0
Washington-Oregon	0	0	0	0

TABLE B. Measured of undiscovered recoverable resources, 0-200 meters water depth. 1/
(Oil in billions of barrels and includes natural gas liquids)
(Gas in trillions of cubic feet)

Area	Estimated undiscovered recoverable resources Oil	Estimated undiscovered recoverable resources Gas
Southern California	0-5	0-10
Santa Barbara	0-5	0-10
Northern California	0-5	0-10
Washington-Oregon	0-2	0-3

1/ On March 26, 1974, the U.S. Geological Survey released estimates of the undiscovered recoverable oil and gas resources for broad areas of the OCS. Those estimates were based on statistical parameters of oil occurrences that apply only to broad geographic areas. It is entirely inappropriate to apply the same parameters to small, specific areas. The resource figures in the above table represent a general estimate, based on the above referenced table, of minimum and maximum volumes of oil and gas that might be recovered from the various OCS areas. It is statistically unsound to add the maxima and minima for an expectable range of resources for any larger area.

TABLE C. Current (1972) oil and gas production from coastal State waters.
(Oil in billions of barrels and includes natural gas liquids)
(Gas in trillions of cubic feet)

Area	Oil and gas production (1972)	
	Oil	Gas
Southern California	0.1	0
Santa Barbara		
Northern California	0	0
Washington-Oregon	0	0

TABLE D. Estimate of undiscovered recoverable resources in coastal State waters. 1/
(Oil in billions of barrels and includes natural gas liquids)
(Gas in trillions of cubic feet)

Area	Estimated undiscovered recoverable resources	
	Oil	Gas
Southern California	0-1	0-3
Santa Barbara	0-1	0-3
Northern Calfornia	0-1	0-3
Washington-Oregon	0-1	0-3

TABLE E. Measured and inferred reserves, coastal State lands (L2-31-72).
(Oil in billions of barrels and includes natural gas liquids)
(Gas in trillions of cubic feet)

Area	Measured Reserves		Inferred Reserves	
	Oil	Gas	Oil	Gas
Southern California	0.7	0.7	0-.5	0-.5
Santa Barbara				
Northern California	0	0	0	0
Washington-Oregon	0	0	0	0

The 1973 production on Pacific coast upland was 335, 741, 000 bbl oil and 478, 356 MCF of gas.

1/ Ibid.

(6) Military Uses

The continental shelf area, (and beyond), of the Pacific Coast of the Continental United States is used by the United States armed forces for a variety of purposes. The main areas of activity are located off the coast of central and northern Washington, the entrance into San Francisco Bay, and the entire offshore area of southern California from northern San Luis Obispo county to the international waters off Mexico. Military Operations which may impose upon normal marine use by the public are covered in the following references: U. S. Coastal Pilot #7 Pacific Coast (1968); Commander Third Fleet Operations Manual 3120 H (1973); Commandant Eleventh, Twelfth, Thirteenth Naval Districts Local Notices to Mariners Annual Publication (L-YR); National Ocean Survey Maps, #5101, #5202, #5302, #5402, #5502, #6002, #6102, (U. S. Dept. of Commerce 1973); Naval Oceanographic Office Map. #18004 (1973).

The major portion of the continental shelf off southern California falls within the Pacific Missile Range which covers some 29,000 square miles and extends approximately 160 nautical miles offshore. This area is used for jet powered target flights, bomb drops, anti-submarine warfare weapons, and general gun firings.

South of the Pacific Missile Range, extending to San Diego and at varying distances from the coast are several Naval operations areas (described in COMTHIRDFLT INST 1973); Long Beach Electronic Test Area, San Pedro; Channel Operations Area; Santa Barbara Island Training Area; San Clemente firing area; Shore Bombardment Area (San Clemente Island); Anti-submarine Rocket Training Area; Camp Pendleton Amphibious Training Area; Cortez Bank Carrier Operations Area. These areas are used for all weather fleet training, refueling, test flights, rockets, bombs anti-submarine warfare, all weather flight training drones, carrier and submarine operations, anti-aircraft and surface gunnery and miscellaneous military operations.

Included in the above areas and extending through the Pacific Missile Range are submarine transit lanes into the Port of San Diego (NOS maps, #5101 & 5202).

In addition to the above operations areas there are two smaller areas of interest: the small arms practice firing range for the United States Army Reserve, National Guard, and Coast Guard units off of Point Fermin (patrolled during firing sessions by safety observers), and the Santa Cruz Anti-submarine Warfare Test Facility, located south of the eastern end of Santa Cruz Island.

Off the coast of San Francisco there are ten areas of operations used for all weather flight training, air intercepts, surface operations, bombing, rocket and aerial gunnery exercises, submarine training and diving operations, and mine warfare operations. The areas are: the San Francisco warning area W-260 (15 miles offshore between Point Arena and Point Reyes), San Francisco warning area W-283 (20 miles offshore between Pescadero Point and Lopez Point), Point Arguello warning area W-281 (15 miles offshore between Lopez Point and Point Piedras Blancas), Point Reyes warning area W-513 (10 miles offshore Point Reyes), San Francisco submarine diving area 1, U2, U3, U4, U5 (located at varying distances off the ocean approaches o San Francisco Bay), and the Monterey Minecraft Operating Area (Monterey Bay). In addition there is a north-south submarine transit lane (Sierra enus) beginning some 40 nautical miles offshore Monterey and continuing south to San Diego, and a restricted access area on south Monterey Bay, (a seaward extension of the Fort Ord Firing Range).

Off the Pacific Coast of Washington there are seven military operations areas used for aircraft bombing, loft bombing, rocket firing, air to air surface gunnery and rocketry, undersea warfare exercises, and submarine training and diving operations. They are Queets R-6707 (Sea Lion Rock - 2.5 nautical miles off the mouth of the Raft River), Washington coastal warning areas W-237, W-237 N and W-237 S, Cape Flaherty W-601, Cape Flaherty Surface Exercise Area 601, and Submarine Trial and Test Areas 3 and 4. In addition there are the following submarine transit lanes; Sierra Altair, Sierra Vega, Sierra Deneb, Sierra Saturn.

Access to all of the aforementioned operation areas is controlled during hazardous operations by radio broadcasts, patrol craft, and notices in "Local Notices to Mariners" published weekly by the Local Coast Guard Districts.

(7) Historical and Projected Economic Growth

(a) Oregon

In Oregon, and Washington, unlike California, major population centers are not on the coastal zone but are inland. Impacts from any major projects would be felt in these areas as well.

(i) Population

Oregon covers a land area of 96,184 square miles which represents almost 3 percent of the total land area in the United States. In size, Oregon ranks number 10 among the 50 states. As of the 1970 Census, total population was 2,091,385 which represents an 18.3 percent increase since 1960. Approximately one-half of this increase was due to people moving into the state.

The largest city in Oregon is Portland. The population as of the 1970 Census was approximately 382,000. The city has shown little change in the past decade with only a 2 percent increase in population. Portland is the economic capital of the state with large banks, law firms, and lumber firms. The port of Portland is an important export point for heavy cargoes like wheat, lumber and wool, and import point for petroleum and ores. Petroleum is a heavy import as Oregon only has one small refinery and is almost extremely dependent on Canadian and Middle East imports.

In 1969 the value of foreign imports and exports handled broke the $1 billion mark. The Port of Portland owns a giant ship repair facility including the second largest floating drydock in the United States. The port also operates the largest dredge in the northwest which is used to keep open and deepen the 110 miles channel to the Pacific Ocean through the Willamette and Columbia River. Although Portland City proper has shown little change, the surrounding suburbs have grown at a fast pace. (Figure 11). The fastest growing counties between 1960-70 in Oregon were within the Portland metropolitan area.

After Portland, Eugene and Salem are the only two Oregon cities with populations of over 50,000 people. Eugene, located 110 miles south of Portland in the upper Willamette Valley, grew in population from 20,838 in 1940 to 50,977 in 1960 and 76,341 in 1970. This represents a growth of 266 percent in three decades and over 50 percent in the past decade. Lane County within which Eugene lies had a population of 213,588 in 1970 which reflects a growth of over 32 percent since 1960.

Salem (the State Capital) with a 1970 population of 68,249 relinquished second place status to Eugene about a decade ago. It finds itself disadvantageously placed so close to Portland (45 miles) that it cannot acquire facilities - major retailing, jetport, etc., of a truly independent big city. Economic activity centers around state government, a prosperous fruit and vegetable canning, industry, and timber. Between Salem and Portland one can now see built-up sub-divisions due to heavy population increases. Not too long ago this was the open valley of the Willamette (Figure 11).

The coastal counties of Oregon from Clatsop to Curry have shown little change in the past decade with the exception of Lane County.

During the past decade Oregon has not been very successful in its hopes for limited growth. During this period the state experienced a population increase of over 18 percent compared to the national average of just over 13 percent. For the period 1970-80 the state is expected to experience almost a 15 percent increase in population. The metropolitan areas of Portland, Salem and Eugene are forecast to increase between almost 16 to 24 percent. If this forecast is realized, Oregon will have had some success in limiting its growth. The coastal counties of Oregon from Clatsop to Curry showed little change during the past decade (excluding Land county) when looked at in total. For the 1970-80 period this picture is expected to change and the rate of growth is expected to be up sharply from the previous decade. Unlike California, Oregon has only a small population in the coastal counties so the increase, if realized, will not impact heavily on the state as a whole.

(ii) Employment and Industry

In 1970 in Oregon the total civilian labor force 16 years old or older was 837,069. Of this total 778,745 were employed, for an unemployment rate of 7.0 percent. In 1973 the average annual employment was almost 973,000 . As of February 1974, the unemployment rate was down to 5.7 percent which compares with the U. S. jobless rate of 5.2 percent.

Oregon is moving from a traditional resource oriented economy - one highly dependent on timber, agriculture and fishing to a more diversified base.

In 1950, 30 percent of all employment in the state was furnished by the combination of the lumber and farm industries. By the end of the 1960s. The 60's brought a doubling of employment in metals and machinery, for instance, and a two-thirds growth in finance, industry, realty, and services. By 1970, jobs in the lumber industry were down to 67,100, some 26,000 less than in 1950. The new figure represented less than one-twelfth of the work force and was still falling, an achievement remarkable in light of Oregon's continuing capability to supply most of the nation's plywood and a quarter of its softwood lumber.

The new industrial fields were diverse in the extreme; metals, freeze-dried foods, women's sports clothes, etc. Outside of forests, Oregon is devoid of significant natural resources; thus its appeal to new factories has to be based in major part on the availability of a well-educated work force, known for its high productivity.

Oregon's gross state product is just below $10 billion a year, compared to California's $126 billion. In terms of single industries, timber still leads (value added $1.8 billion a year), followed by agriculture (over $560 billion in farm sales) and tourism $325 million in 1970). In terms of the "big three" commercial fishing is no longer a very important industry but it still brings in a harvest of salmon, tuna, clams and shrimp worth about $22 million a year.

Oregon has not become dependent in any significant way, on federal spending; it ranks 48th among the 50 states in the percentage of its population employed in defense-related industries, getting only a quarter of the military contracts which go to Washington state or 1/64 of those for California. As of 1970, Oregon's per capita income at $3,718 ranked behind both Washington and California and was 5.5 percent below the United States average. In 1971 this picture changed slightly and some headway was made.

Total personal income in Oregon between 1964 and 1971 increased from $4,851 to $8,446 billion dollars (current dollars). This increase (73 percent) is similar to the U.S. growth in personal income.

(iii) Agriculture

Of the "big three", the industry that has failed to keep pace is agriculture. Just after World War II, Oregon farm income was $246 million a year and represented 18 percent of all salaries in the state; by 1970 it was down to $174 million, representing a scant 2.2 percent. Increased farm productivity accounted for a sharp drop in the number of farm workers and farm payrolls, but even in the inflationary 1960s farm sales rose less than 20 percent.

Oregon harvests over a million acres of wheat each year (traditionally the major crop), with hay, tree fruits, nuts, many varieties of berries, truck crops, potatoes, and seed crops all runners-up; a thriving greenhouse and nursery business has also made the state first in the U.S.A. in Christmas holly and Easter lily bulbs. Livestock production, however, brings just as much income as the crops combined. The Willamette Valley, it is said, has the potential of feeding up to 12 million people, and agribusiness there is already so successful that Salem is claiming it has bypassed San Jose, California, as the biggest single food-processing center of the U.S.A.

(b) Washington

(i) Population

Washington state covers a land area of 66,570 square miles. This compares with Oregon with approximately 96 thousand and California with 156 thousand square miles. As of the 1970 Census the state's population was 3,409,169 people which represents a 19.5 percent increase compared to the same period 10 years earlier. The rate of migration into Washington was the lowest of the three coastal states during the past decade. In total population level, Washington trails only California among all states west of the Rockies. Approximately three-quarters of the population live west of the Cascades or about one-third of the land area.

The capital of Washington State is Olympia which is located at the southern tip of Puget Sound. As of 1970 the population was 23,296 which compares with the 1960 population of 18,273.

Seattle is the largest town in Washington with a population in 1970 of 530,890. While Seattle's population actually declined during the 1960's by 4.7 percent, the Seattle-Everett Metropolitan Area as a whole added 300,000 people for a new total of 1,421,869. This was due largely to a 64.3 percent population increase in the suburbs.

The Port of Seattle, closest on the West Coast to the Orient and capable of handling the deepest-draft ships, has passed Portland in total tonnage. Port activity generates some 17,000 jobs and hundreds of millions in annual payrolls, and it could get even bigger if the Alaskan oil pipeline from the Northern Slope is built and quantities of oil super-tankers begin to deliver oil from the pipeline terminal on the Bay of Alaska to Puget Sound.

Spokane, close to the east-central border of Idaho, is the second largest town in Washington with a population of 170,516 (1970), and is the only city of any size outside the Puget Sound area.

Tacoma, the state's third largest city with 154,555, lies almost midway between Seattle and Olympia (the Capital). It is a large lumber center and also is known for the manufacture of furniture. With the exception of the above 4 mentioned cities of Seattle, Spokane, Tacoma, and Bellevue, there is only one other city with a population over 50,000. This is the town of Everett in Snohomish County north of Seattle.

Washington's population increased between 1970-71 by 17,000 but decreased 11,000 between 1971-72. The 1973 population stands at approximately 3,424,000, which reflected an increase of less than 1/2 of 1 percent between 1970-73.

The four coastal counties of Washington, Clallam, Jefferson, Grays Harbor and Pacific, had a 1970 population of 120,780. This represents approximately 3 1/2 percent of the total state population. The principal occupations in this area are lumber and commercial fishing.

(ii) Employment and Industry

The labor force in Washington in 1970 totalled 1,400,400 people, 41 percent of the population of that state. Of this total 1,283,500 were currently working, reflecting an unemployment rate of 8.3 precent.

Washington has shifted rapidly from an old wheat-timber extractive industry base to a manufacturing economy. Before World War II, three-quarters of employment was in agriculture and forest products; now it is one-third, while aerospace and other business accounts for two-thirds of the jobs.

Manufacturing is a significant part of the Washington economy, with value added each year of more than 3 billion. In peak years, aerospace has accounted for $1 billion. Food and wood products, metals, chemicals, machinery, and ship-building are all important. Inexpensive power from hydroelectric dams along the Columbia are responsible for a $400 million-a-year aluminum reduction industry. Unlike the state of Oregon, Washington State depends heavily on government contracts in the aerospace industry. This has been responsible for major economic ups and downs in Puget Sound area. The Boeing Company's plants are set in a string from Auburn south of Seattle to Everett in the north, and it has a major influence on the economy of the area but when Boeing's orders begin to dwindle seriously as they did at the start of the 1970's, the result can be widespread unemployment. Between the 1968 peak employment for Boeing and December 1971, 71,500 jobs were lost in the Seattle-Everett area due to a cut-back by this one employer. The unemployment rate for this area jumped from 2.5 percent in 1968 to 13 percent by the end of 1971. This points up the problems of having a single industry having a large influence on the economic climate of a major metropolitan area. With a more diversified economy these problems can be avoided to a large extent, currently with additional government contracts ($1.7 billion in 1975) the outlook for Boeing and the area's economy is looking stronger.

In the 1960's and early 1970's there were cutbacks in military and civilian personnel on military bases and some bases were closed down completely. Since then the picture of other bases has become more secure in the light of other closures nation wide.

Federal agencies in the Seattle area employ 16,000 workers and contribute $200 million to area payrolls. Prospects for increases employment in this area are good.

Agriculture for many years has been a declining industry in terms of employment, here as well as nationally. During the past quarter century, farm employment has declined 57 percent nationally and 30 percent in Washington State. The difference here is due in major part to an increase in irrigated acreage east of the Cascades. Because of additional potential in irrigation, this state also has better future prospects in agriculture than the nation.

Employment for the "other manufacturing" category (beside forest products, food processing and aerospace) as a whole last year averaged 98,000 workers, or roughly 40 percent of all manufacturing. Ten years ago, the figure was 30 percent. This trend is important because of the absolute addition to the work force, and because of the balance it provides to an economy long dominated by a resource-based and defense aerospace manufacturing core.

Washington State holds attraction for new industry in four broad areas. First are the available raw materials native to the region, principally in forestry, agriculture, and fisheries. If the summaries of announced plant expansion and new industry investment of the State Department of Commerce and Economic Development are taken as a general guide, nearly half, or 48 percent, of new plant investment since 1970 falls into this category, 20 percent in machinery and metals, 12 percent in chemicals and petroleum, and the remainder scattered. Additional food processing, most notably potato processing in the Columbia Basin, and modular homes in lumber and wood products, have been notable new resource-based entries.

One further element, which has done much to augment the industrial base in the past and may still have impact in the future, is the state's favorable position with respect to electric energy. More than 90 percent of Pacific Northwest power is hydroelectric, in contrast to less than 10 percent for the rest of the nation, and this is a replenishable resource. Six more generating units are coming on line at Grand Coulee between now and 1978 to effectively double output there. Energy costs are rising in this region but will still be low relative to other areas. This holds promise for greater diversification into industrial expansion.

Washington ranked thirteenth among the 50 states in per capita income as of 1970. This compared with Oregon and California which ranked 22nd and 8th, respectively. Washington State's level of per capita income in 1970 was above the United States average but since then it has increased at a slower rate and currently is slightly below the U.S. level.

In constant dollars (1967 base) Washington's personal income has increased almost 50 percent between 1964 and 1972 to a level of 12.8 billion dollars. This is the same rate of increase as achieved by the United States as a whole and represents 1.6 percent of the U. S. personal income.

(iii) Agriculture

Annual farm income is about $800 million a year. Washington ranks fifth in U.S. wheat production, and in recent years has been first in apples, a $50-$75 million crop grown chiefly in the valleys of the Cascades. Washington is first in hops and red raspberries and ranks high in potatoes, pears, cherries, and asparagus. Many of these crops are grown in truck farms in the Puget Sound lowlands. Livestock and dairy products account for about a third of the farm income. Still a factor, though not a big one, is an annual fish catch (salmon, halibut, shellfish) valued at $31 million. Mining for a miscellaneous group of ores brings in over $90 million.

The amount of irrigated farmland in Washington has grown from 589,035 acres in 1950 to 1.5 million acres today and amounts to almost one-tenth of all agricultural land in the state. The water comes from wells, slack water pools behind power dams, and directly from the Columbia River and its tributaries. The majority of the lands irrigated at present have been developed by the Bureau of Reclamation; in 1972 the vast Columbia Basin and Yakima Valley projects together accounted for about 55 percent of Washington's irrigated acreage and brought in 30 percent of the state's gross crop value.

(c) The Future in the Pacific Northwest

(i) Population

The future growth in population is dependent upon the economic development in the region. Preliminary forecasts indicate a population increase of 115 percent between 1965 and 2020, compared to 105 percent increase for the nation. The Willamette and the Puget Sound areas are projected to experience annual rates of growth significantly greater than that of the region as a whole. By the year 2020 it is expected that the coastal zone, the Willamette and Puget Sound areas, will have about two-thirds of the population in the Pacific northwest.

(ii) Employment and Industry

Total employment for the region is estimated to increase approximately 150 percent between 1960 and 2020. Employment, like population, will tend to be concentrated in the western portions of the Pacific Northwest. Employment in the manufacturing sector is projected to double in the next 50 years. Manufacturing over this period is expected to be about one-third greater than the national rate of growth and the greatest part of this growth will come from the non-resource oriented activities.

(iii) Agriculture

Agriculture is expected to continue as an important industry in the future, with output increasing nearly one and a half times by the year 2020. The production of all crops will increase by about 160 percent, and all livestock and poultry, 131 percent. Increases in output by subregions will range from two to threefold by 2020. Agricultural employment, on the other hand, will decrease substantially in the region by 2020.

Projected increases in agricultural output will be accompanied by changes in the structure of the agricultural industry. Substitution of capital inputs for labor and land, as well as shifts in the organization and use of resources, will continue. Further reductions in the numbers of farms are expected as smaller farms are consolidated into larger commercial farms. Increased productivity per worker and per acre will be influenced primarily by additional resource development, such as irrigation and drainage, new technology, and more extensive use of capital inputs.

(d) California

(i) Population

California covers a land area of 156,361 square miles and as of the 1970 Census had a population of 19,957,715. The population density was 128 persons per square mile which compares with 51 for Washington and 22 in Oregon. California experienced a 27.1 percent population increase between 1960-70 which is the largest of the 3 Pacific Coast states.

In 1973, California had an estimated population of 20,850,000. This reflects a 1.1 percent increase as compared to a year earlier. The two fastest growing metropolitan areas were Orange and San Diego counties, with respective increases in population of 65,000 and 39,000. Los Angeles County has the only Standard Metropolitan Statistical Area in California to show a decrease, having approximately 31,000 fewer people than in 1972.

Southern California's coastal counties from Santa Barbara to San Diego had an estimated population of 10,803,000 people by the end of 1973. This represents slightly more than one-half the populace of the entire state. This area (Southern California) experienced a one percent increase in population in 1973. This is approximately the same rate of growth as experienced by California and the United States as a whole.

During the century following 1860, California's population doubled five times, or once each twenty years. In the period 1960 to 1970, California's population increased 27 percent, which was more than double the average growth rate for the United States. Since 1970 the rate of growth in California has stabilized and at present time approximates the national growth rate of 1 percent a year.

The unusual rate of growth which California experienced through 1965 is no longer possible not only because of the very size of the base, but also because in absolute terms, net migration and the number of births has declined substantially. In the past 5 years the level of migration has averaged about 207 per day more arrivals to the state than departures. This is substantially below the "thousand per day" which was common place a decade ago.

The greatest stimulus to California's economic and population growth came between the years 1950-1960 as a result of new highs in defense spending. The impact of defense spending affected major changes in California's growth patters. Some urban centers have grown more rapidly than otherwise would have been the case. This was most obvious in the areas around Los Angeles, San Diego, San Jose and Orange counties. Defense spending stimulated the expansion of the manufacturing sector of the economy during the 50's which created new employment opportunities and the resultant population expansion.

The pressures that have been put on California's coastal zone as an attractive location for industrial and military developments has also brought heavy urban development; consequently the heavy population centers are to be found here. The heavy influx of people combined with a search for "cheap land" has helped lead to the urban sprawl as seen today.

Coastal areas are expected to experience continued growth by recent projections, with the exception of the Los Angeles County area. Projections for the L.A. area vary from a continued increase in population to a shallow decline. Some of the basic reasons given for a decline in population are crowded conditions, a drop in birth expectations and decrease in net migration.

On the Northern California coast only two counties, Del Norte and San Francisco, recorded a drop in population between April 1972 and April 1973. Overall population grew by almost 67,000 in the northern counties. Net migration occurred in 4 of the 16 coastal area counties. In the 5 county San Francisco - Oakland Metropolitan Area, overall population growth was less than the natural increase, indicating a net out-migration for the April 1972-73 period.

(ii) Employment and Industry

According to the 1970 Census the civilian labor force in California was 7,992,168 people of which 7,484,690 were employed. This reflects an unemployment rate of 6.3 percent. As of 1973 the civilian labor force had grown to almost 9 1/4 million men and women and the unemployment rate had dropped to 5.1 percent. Non-agricultural employment accounts for about 97 percent of the entire civilian labor force in California. The principal business sector employers were trade, which accounted for 19.7 percent of those employed, followed by manufacturing (18.8%), government workers (17.5%) and the services sector (17.1%).

There was a substantial increase in jobs during 1973 with non-agricultural wage and salary employment up approximately 6 percent, the largest gain since 1966. In the service sector, growth was particularly strong (9.4%), trade and manufacturing were up slightly more than 6 and 7 percent, respectively.

In the five Southern California counties from Santa Barbara to the Mexican Border, manufacturing employs the greatest number of people for any single sector. In 1972 almost 1 million people were employed in this area, with Los Angeles County employing almost 80 percent of the total, and Santa Barbara County employing as little as 1 percent.

Trade provides the second largest number of jobs among Southern California Coastal Counties. At the present time, over 900,000 workers are employed in wholesale and retail trade, representing better than one out of five jobs. Traditionally, trade has been one of Southern California's most rapidly growing employment sectors and shows less sensitivity to business fluctuations than most other industries. In 1973 strong growth in consumer expenditures and the accompanying economic expansion impacted directly on trade employment. The level of employment in 1973 showed strong increases over the same period in 1972.

Ranking third among major employment sectors, the service industry has reflected trends very similar to those in the trade category and for essentially the same reasons. Services, which employs approximately 3/4 of a million people in Southern California, has shown steady gains during the past decade except for a one-year disruption during the 1970 recession.

Government employment provides the fourth highest number of jobs in Southern California Coastal counties. This sector evidenced strong growth in the sixties thru the present time. The increases are almost entirely due to large increases in state and local government, as Federal employment has remained fairly level since the middle 1960's.

Employment in transportation, communication and utilities reflected steady increases in the late 1960's which was followed by a cutback in 1970 and 1971 during the recession. Since that time steady increases have been made in this sector.

Los Angeles County accounts for more than 70 percent of the employment in the five Southern California coastal counties, and has historically registered the greatest numerical change in employment. However, the county's high degree of development leaves relatively little room for growth, and employment expansion consequently has been less rapid than in other large Southern California metropolitan areas. Despite recent diversification, the vast aerospace complex is still centered in Los Angeles County although certain industry shifts are currently underway. Therefore, cutbacks in NASA and Department of Defense contracts are felt to a greater extent in Los Angeles than in other Southern California employment centers.

Orange and San Diego Counties account respectively for approximately 12 and 11 percent of the five Southern California coastal counties employment and have both been registering rapid employment gains. Each of the two areas has ample room for further development and are expected to continue to register a considerably faster growth rate than the rest of the Southern region.

Ventura and Santa Barbara Counties account for less than 5 percent of the South Coast total work force. Although small in labor force, Ventura County continues to be one of the fastest growing regions in California. Of significance is that this area's employment growth is broadly based, as opposed to one industry inspired gains.

Non-agricultural wage and salary employment in northern coastal California's eleven metropolitan counties posted almost a 5 percent gain in 1973. Manufacturing in 1973 added 30,000 new jobs and was up 9 percent compared to a year earlier. Most of the gain was in durable goods, especially in the electronics industry centered in

San Mateo and Santa Clara Counties. Building permit activity showed little growth during 1973 and reflected a 1.4 percent gain.

For California as a whole the overall employment outlook for 1974 points to a substantial weakness for the better part of the year with some improvement occurring during the closing month of 1974. Civilian employment is forecast to increase less than 1 percent over the entire year, declining on a seasonally adjusted basis during the first half.

Total personal income in California for 1973 totalled $112 billion up almost 10 percent compared to a year earlier. Compared to the total U.S. personal income, California accounts for 11 percent and has the highest personal income of any individual state. Wages and salaries make up about 2/3 of the total income figure. Los Angeles County with a personal income of $41,845 million combined with San Francisco and Oakland areas income of $20,742 million account for more than over half of the total.

After recording vigorous growth in 1973 personal income is expected to advance at a slower rate in 1974. Slower employment gains are expected to alter gains in wages and salaries, and a net increase of 8 percent is forecast.

(iii) Agriculture

California's number one industry - agriculture, led the nation in case farm receipts in 1972 for the 25th consecutive year. Receipts reached a landmark of $5.5 billion, almost a billion dollars greater than Iowa, the second ranked state.

The number of farms has fallen by more than half since 1950 and is expected to drop to 30,000 by 1980. At the same time total acreage has shown little change and between 1950 and 1970 dropped less than 2 percent. The trend in California and the United States is towards fewer farms but with larger acreage as the cost-price squeeze forces the "little man" to sell out. In the past 20 years the average size of a farm has more than doubled and the average invested value of all California farms is almost one-third of a million dollars.

In 1972 California's cash farm receipts represented almost 9 percent of the total cash farm receipts for the nation which was produced on only 2 percent of the farms. In ranking of State, California is 1st in production of 47 commercial crop and livestock commodities.

"California's Top Twenty" crop and livestock commodities accounted for 80 percent of the states gross farm income in 1972. Cattle and calves and dairy products continue to dominate the livestock industry, while grapes, cotton, hay and tomatoes are the most important crops.

California's agriculture is considered one of the most diversified in the world, with no one crop dominating the states farm economy. This is illustrated by the fact that most crops individually account for less than 3 percent of the state's total gross farm income.

California leads the nation by a wide-margin in the production of fruits and vegetables, and maintains about 8 million acres under irrigation, largely for the production of speciality crops. Even with California's larger population it is important to note that approximately 90 percent of the water use in the state is for agriculture.

In California the average value of agricultural land varies from as high as $5,000 per acre for irrigated orchard land in Southern California to as low as $170 per acre for rangeland in the Sacramento Valley.

Of the 5 Southern California coastal counties Ventura County ranked 1st in value of production. The major commodities were fruits and nuts, which were responsible for almost 1/2 of the gross income attributable to agriculture. Vegetables was also a primary source of income.

In San Diego County, the major commodities were eggs and tomatoes. Farm acreage is presently on a downward trend in the country due to a heavy population increase and urban encroachment. Los Angeles County is the only Southern California coastal county which reflected a decrease in total farm income in 1972. This was mainly due to drop in livestock and poultry production of more than $6.5 million dollars. A steady exodus of dairy animals was also a significant factor.

Santa Barbara County has more than 1/3 of the agricultural land in Southern California, yet accounted for only about 14 percent of the gross value of sales. Their leading products are cattle and calves and broccoli.

The central valley of California which consists of the Sacramento and the San Joaquin Valleys is a major agricultural producing area. Farm production in the San Joaquin Valley alone exceeds that of 44 other states and 3 counties within it - Fresno, Kern, and Tulare, lead all counties in America. One reason this is possible is due to the long growing season in some areas of 9 to 10 months. The valley produces a large variety of fruits, vegetables and field crops such as grapes, olives, lemons, tomatoes, prunes, wheat, etc. The valley is also a major produces of beef and dairy cattle.

California's great vineyards - in the Napa and Sonoma Valleys north of San Francisco and the Salinas Valley near Monterey produces 85 percent of the United States wine output, a $700-million-a-year business for the state.

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Agriculture in California is not only important in supplying food to the nation, but for many other reasons. It has created many jobs in commerce and industry, and contribute directly or indirectly over $19 billion a year to the states economy. The states farm production accounts for 1/2 of the total tonnage shipped by trucks and approximately 1/2 of the value of water borne exports from California ports. There are nearly 3,000 manufacturing plants for processing food and kindred products.

d. Existing Environmental Quality Problems in Coastal Zone

(1) Water Quality

Southern California

The following descriptions have been taken from the California Region Framework Study Committee (1971).

In the San Diego Bay area, large quantities of wastes in the form of raw waste water, garbage, trash, grease and oil are one of the causes of pollution of the Bay.

Because of water deficiency, extensive ground-water recharge projects using treated waste water are operated. Most percolation beds are in river channels or on land near streambeds. During the rainfall season, treated waste water overflows from percolation beds and/or from drains in irrigated fields. Nutrients from waste water combine with the urban runoff to enrich many coastal lagoons. The enrichment promotes excessive algal blooms and aquatic growths, oxygen depressions and odor problems.

The submarine outfalls of the South Coastal Subregion are among the largest in the world. In addition, there are numerous small discharges through short outfalls serving smaller coastal cities. Where disinfection practice is marginal, smaller outfalls are sources of coliform bacteria to the recreational beaches and shellfish areas. Floatable materials from marine outfalls, channel debris and waste from vessels have been a major concern in waters near Los Angeles and Long Beach and many other marine shore communities.

The estuarine area of the San Gabriel River receives condenser cooling water from two large (1,000 megawatts) thermal-electric power plants, with a resulting 15° to 18°F increase in estuarine water temperatures. As a result of the increased temperature and the natural nutrients in these waters, a tropical aquatic ecology has developed in the estuarine reach. During the heavy runoff season, the high stream discharges flush the estuary, transporting large quantities of aquatic growths to San Pedro Bay. The decomposition of these aquatic mats creates potential pollution and odor problems which can adversely affect the beneficial uses of San Pedro Bay.

The Los Angeles-Long Beach Harbor complex receives large volumes of municipal and industrial waste which depress dissolved oxygen levels and cause odor problems. Waste brines from refinery and oil fields are discharged into the inner harbor.

In the area along the coastal waters of Ventura County, brine and waste waters from nearshore and offshore oil well development are sources of oil contamination in beach areas. Several large submarine oil seeps in the area contribute to the problem of the extensively used recreational beaches. On the Channel Islands, also offshore of Ventura County, a zero hatch of Brown Pelican eggs has been reported as being related to pesticides, e.g., only one pelican was produced out of an estimated 1,000 plus eggs layed during the 1970 nesting season.

Central California

Water quality problems presently exist within the Central Coastal Subregion as illustrated by such recent events as bacterial contamination of recreational coastal areas at Monterey and Carmel, the massive offshore oilspill incident near Santa Barbara (January, 1969), the occurrence of algal growth in parts of the San Lorenzo River, localized inland pollutional problems directly attributable to irrigation drainage and waste discharges and deteriorating groundwater quality.

Bacterial contamination is evident in certain portions of Monterey and Carmel Bay where recreation demand is very high. Coliform bacteria, an indication of the level of pollution, has exceeded the standards for water contact sports from Seaside to Monterey and a portion of Pacific Grove beach area. Problems of this nature are closely allied to the lack of adequate treatment of municipal waste at various locations and also other industrial discharges.

Near the southern portion of the subregion along the coastal waters off Santa Barbara and Ventura Counties, brine and waste waters from nearshore and offshore oil well development and natural seeps from the ocean floor are potential sources of oil pollution in beach areas. A large submarine oil well operation on the outer continental shelf contributed to an extensive oil pollution incident near Santa Barbara which resulted in oil-coated beaches, killed thousands of waterfowl, endangered nearshore ecology, and coated boats and structures, all of which resulted in tremendous economic loss to this recreational area. The chance for recurrence of oil spillage is present although tighter safety precautions have reduced the probability of large spills.

Due to the intermittent nature of most inland streams in the subregion, water quality degradation results. This occurs through drainage from irrigated lands reaching relatively dry streambeds, thus forming the major portion of streamflow. Other incidents of water pollution result from bypassing or overflow from land disposal areas for municipal waste water to drainage-ways or streambeds. When streamflows reach levels of flooding conditions, the accumulated waste constitutents from overflows, refuse or solid waste in the streambed is washed downstream to estuaries and bays.

San Francisco Bay Area

The high sediment load and turbidity in the Russian River has been a source of complaints by fishery interests. Water is imported from the adjoining Eel River Basin during the low flow season when eutrophication of impounded and flowing waters is evident. The large nutrient loads from treated waste water, septic tanks, and natural runoff have been a cause of prolific algal blooms along this recreational waterway. Bacterial contamination has been a problem in the Russian River Basin, although now minimized by recently constructed facilities. At the mouth of the river near Jenner, seawater intrusion into ground-water has been a local problem.

Tomales Bay, Bolinas Lagoon, and Bodega Bay experience violation of minimum bacteriological standards due to the discharge of municipal waste and dairy waste.

Depressed levels of dissolved oxygen in the extreme portions of South San Francisco Bay occur during the late summer and early fall months due to municipal waste discharge. Dissolved oxygen deficiencies also occur in the Petaluma River and are attributed to dairy waste discharges and the City of Petaluma's waste discharge. Widely fluctuating levels of dissolved oxygen observed in areas of limited circulation in San Francisco Bay and in adjacent coastal areas have been attributed to algal growths. These growths have caused complete lack of dissolved oxygen in the extreme reaches of some tidal sloughs, creeks and rivers, and have caused pH values up to 9.0. Green seaweed along mudflats are particularly apparent in the Bay system during the summer and fall when decomposing mats emanate hydrogen sulphide. Recent years have brought red water discoloration caused by a planktonic marine organism , a phenomenon probably aggrivated by high nutrient concentrations.

Fish kills have occurred in the Bay system as the result of accidental spills of toxic materials and inadequately treated waste water and industrial waste discharges. Major kills of striped bass and sharks have occurred in Suisun Bay, Aquatic Park, and near Alameda with the cause generally unknown.

Pesticides in the Bay system originate from municipal storm sewer and sanitary sewerage systems, urban runoff and drainage, and from the vast agricultural lands in the Central Valley. The presence of these pesticides is as yet a threat of unknown magnitude to the fisheries and wildlife resources. This threat must be more fully evaluated and all agricultural drainage facilities serving the Central Valley should be carefully monitored and treatment or control measures instituted where warranted.

Recent studies made as part of the San Francisco Bay-Delta Water Quality Control Program found that, of the seven sub-areas of the Bay system, only the North San Francisco Bay appeared to conform with the bacteriological objective adopted by the Regional Board for the protection of the public health. Substantial improvement in the bacteriological quality of the waters of Central San Francisco Bay has been reported by the State Department of Public Health after the initiation of disinfection of waste discharges by East Bay Municipal Utility District and the City of San Francisco at its Southeast Plant.

At present, all portions of the Bay system are quarantined by the State Department of Public Health for harvesting shellfish for human consumption because of contamination by waste discharges. The delineation of areas to be protected for shellfishing are available from the State Department of Fish and Game.

Sediment and turbidities are important factors affecting bottom organisms and the aesthetic values of the waters. The past oyster fishery has been lost due in part to sedimentation. Deposited sediments are resuspended by maintenance dredging of navigation channels and boat harbors, deepening of navigation channels, overflows from hydraulic landfills, wave action from vessel wakes, and wind and tide induced currents.

Water quality problems resulting from the filling the tidelands are numerous, complex, and not fully understood. They are the subject of study by various agencies including the San Francisco Bay Conservation and Development Commission (BCDC) and the State Water Resources Control Board. Under recently enacted legislation, any person or governmental agency planning to fill the Bay, or to extract submerged materials from the Bay is required to secure a permit from the BCDC.

Limited data are available on the effects on water quality by discharges from combined waste water systems, bypasses of waste water from sanitary waste water systems overloaded because of storm water, and the discharge of storm water runoff. Nevertheless, obvious problems are the direct result of such discharges.

The discharge of oily wastes and waste water from boats and vessels is a water quality factor associated with navigation and recreational boating, causing conditions contrary to water quality objectives. Presently there are local efforts to connect houseboats to sewer systems. Recent State legislation (1970) and vigorous enforcement should adequately control the houseboat problem.

The San Francisco Bay area has experienced oil pollution problems localized at refinery docks, ports, marinas, and near storm sewer outlets attributable to accidental spills, deliberate discharges, pipeline leaks and pumping of oily bilge or ballast water. During the period of January, 1968, to June, 1969, 235 oil spills were reported in San Francisco Bay from all sources.

Waters near the City of San Francisco discharge points and beach areas both in the ocean and inside the Bay usually do not meet bacterial standards for swimming quality. San Francisco has a combined sewer system which, during wet weather, discharges untreated waste water to the Bay and the Ocean causing contamination.

The deep coastal water disposal of cannery wastes, industrial wastes from petro-chemical processes, waste from steel operations, explosive and toxic wastes are potential pollution problems. Dredging spoil from existing and new ship channels and bay mud from other construction activities is usually disposed of at designated areas within the Bay system; however, some dredged material is spoiled in the ocean outside the Golden Gate.

Northern California

In the Crescent City and Humboldt Bay area, unsewered subdivisions presently served by septic tanks create pollution problems during the wet season. There is a need to connect these subdivisions to the local municipal system where proper treatment can be provided. Disinfection practices in existing waste water treatment plants including oxidation ponds which discharge to Humboldt Bay should be improved to insure compliance with bacteriological standards in receiving waters to protect the valuable shellfish resource. Harbor pollution from shore installations, vessels, and small fishing and pleasure craft at Crescent City and Humboldt Bay cannot be ignored since bacteriological contamination is likely from these sources. Oil spills have occurred which contaminated shellfish areas, killed water fowl, and affected the estuarine plant foods and birds.

At Ft. Bragg and Noyo Harbor, organic pollution problems are critical. Fort Bragg does not have a community sewerage system and discharges raw waste water directly to the ocean. Fort Bragg is the last town of its size (5,000 pop.) in the California Region to discharge untreated waste water to surface waters. Noyo Harbor does not have a community sewer system, and individual septic tanks and cesspool systems are common in the harbor. Fish processing plants, restaurants, fishing boats and other commercial enterprises have added to the pollution problems of the harbor. Fish kills have occurred in the Noyo River as a result of pollution.

Erosion and siltation are major problems of all drainage basins in the North Coastal Subregion. Land disturbances related to logging, road construction, mining and forest fires have contributed to turbidity and siltation of North Coastal streams. Siltation of stream bottoms smothers sensitive benthic fauna essential to fish production. Clogging of spawning gravels further reduces recreational fishery production so important to this area. Proper land management designed to control excessive sediment production in the subregion is essential to maintenance of the present North Coastal aquatic environment.

Mine drainage within the North Coastal subregion has on occasions caused severe losses of fish due to high dissolved solids loads or heavy metals, such as copper, being discharged from active and abandoned mining operations.

Pesticide concentrations in the lower Lost River are presently high enough to cause concern about the effect on the aquatic environment and wildlife.

Oregon & Washington

The following information has been taken from the North Pacific Region Comprehensive Framework Study (1971).

In general, the waters of the subregion are of excellent quality and are suitable for all uses. The most commonly encountered problems include high coliform bacterial counts, high temperatures, and high nutrient levels. A few instances of low dissolved oxygen are found, and high turbidities and sedimentation are encountered during some periods of the year. Water quality deterioration from toxic materials has not been documented, although phenolics associated with plywood production and sulfites associated with pulp and paper production are discharged to subregional waters.

The marine and estuarine waters of the subregion are of prime importance for recreation, as clam and oyster rearing areas, and for passage of anadromous fish. In several estuaries, discharges of untreated or inadequately treated domestic and industrial wastes and agricultural runoff have seriously degraded water quality. These estuaries include Coos Bay, Umpqua Bay, Yaquina Bay, Nehalem Bay, Tillamook Bay, and Grays Harbor.

Dissolved oxygen levels are generally satisfactory for fish passage in most marine waters; however, Coos Bay, Yaquina Bay, and Grays Harbor do exhibit oxygen depressions during certain periods of the year. In Coos Bay, oxygen levels of one to two mg/l have been reported during late summer and early fall. In Yaquina Bay and Coos Bay, depletion of water quality during the summer months is caused by the very low inflow into the bays and large waste loading. This inflow is not large enough to allow flushing and, thus, a pool of water is trapped until high water flows force the water out. A periodic phenomenon in Grays Harbor which results from particular conditions of wind and current, referred to as upwelling, replaces bay water with low DO water which is forced up from great depths offshore. The DO content of the deeper waters may be as low as one to two mg/l. When upwelling occurs during the season of high temperatures and low streamflow, it reduces the estuary's ability to provide the needed oxygen resource and thereby intensifies the oxygen deficit.

In several areas of the Oregon Coast, discharges of untreated or inadequately treated domestic and industrial wastes and agricultural runoff have reached the point of causing a threat to health. These areas include Nehalem Bay, Tillamook Bay, Yaquina Bay, and Umpqua Bay. The most significant of these areas are Yaquina and Tillamook Bays, where recently the Public Health Service "conditionally approved" oyster growing areas with the stipulation that action be taken to reduce coliform levels in the bays.

Toxic sulfite waste liquor effluents from pulp and paper mills and phenolics associated with plywood production have deteriorated water quality in Coos Bay, Yaquina Bay, and Grays Harbor. The discharges have resulted in unsightly and interfering floating materials as well as rendering some areas sterile for normal aquatic populations.

(2) Air Quality

In terms of air quality problems along the Pacific Coast Zone the only significant areas are located in Southern California, particularly in the Los Angeles Metropolitan Area. The other areas have minor problems which are not considered to be significant. The areas outside of Southern California do not have existing problems that would be aggrevated by the introduction of offshore oil and gas activities.

In the state of Washington the coastal zone is limited to a narrow stretch between the Pacific Ocean and the Olympic Mountains. It is located within the southwest region, a division of the state air pollution control function, and represents one broad air basin. The two main urban areas are centered around the Grays Harbor area and the Astoria, Oregon point on the Columbia River. The Washington Department of Ecology reports that there are no air quality problems existing in the coastal zone because of the flushing action of the winds, the lack of major industry, and the small number of automobiles. There are minor local disturbances of air degradation resulting in particulate matter emissions from the lumbering industry, but a close monitoring system is maintained by the air control agency.

The air quality situation along the coastal zone in Oregon is very similar to that of Washington. The coastal zone is a narrow band located between the Pacific Ocean and the coastal range of mountains and is mostly forrested with the exception of the small urban centers. The lack of air quality problems is evidenced by the fact that the Oregon Department of Environmental Quality only has intermittant monitoring along the coast.

The stations are located in the Coos Bay area and in Astoria along the Columbia River. In Coos Bay the monitoring program is directed towards particulate matters that originate with the lumbering industry. In Astoria sulfur dioxide emissions are monitored. Because of similar terrain and wind actions as that found in Washington, there are no air quality problems of any significance.

The major air pollution problem in California is photochemical air pollution which is caused by atomospheric reactions of hydrocarbons and oxides of nitrogen in the presence of sunlight. Although of less severity, carbon monoxide and suspended particulate matter do affect the ambient air quality. Problems caused by other pollutants such as leads, nitrogen dioxide and sulfer dioxide are not as severe but often do exceed the ambient air quality standards.

Low concentration of all pollutants occur naturally although the levels may not be the same in all locations. Common background levels of various air pollutants are shown below and compared with air quality standards.

Pollutant	Background Level	Federal Air Quality Standards
Oxidant	0.04 ppm	0.08 ppm (1 hour)
Carbon Monoxide	1.0 ppm	9.0 ppm (8 hours)
Nitrogen Dioxide	.004 ppm	0.05 ppm (Annual)
Suspended Particulate Matter	20-40 ug/m3	75 ug/m3

Sulfur dioxide and hydrogen sulfide are emitted by localized underground sources and do not have widespread background levels. Natural background levels of particulate matter are created by salt spray and sand near the coast and by wind blown dust and pollens inland.

Large quantities of man made pollutants are emitted into the atmosphere daily. California statewide emissions are as follows:

Nitrogen oxides	3,800 tons per day
Hydrocarbons	5,900 tons per day
Carbon monoxide	24,000 tons per day
Suspended particular matter	1,900 tons per day
Sulfur dioxide	990 tons per day

The South Coast Air Basin (Los Angeles Area) has forty-nine percent of the California population, six percent of the land area, and produces thirty eight percent of the total tonnage of air pollutants.

Emissions from motor vehicles account for the greatest portion of hydrocarbon, oxides of nitrogen and carbon monoxide pollution. Industry and agriculture are responsible for the majority of the man-made particulate matter in the atmosphere.

The South Coast Air Basin in a large flat basin in which air movement is impeded by mountain ranges to the east and north. Prevaling winds from the Pacific Ocean carry the pollution towards the mountains. The condition is aggrevated by an atmospheric temperature inversion which is often present. During the inversion, a layer of warm air overlies cooler air which acts as a lid by trapping pollutants in the lower air mass.

The concentration of all the pollutants commonly measured exceeded air quality standards in the Los Angeles area in 1973. As a result, the air quality problem is significant in the Los Angeles area.

The San Francisco Bay Area has been relatively free of smog, when compared with Los Angeles, because the onshore air flow ventilates the area drawn inland in the summer and fall by the thermal low in the central valley of California. However, concentration of oxidants, carbon monoxide, nitrogen dioxide, and particulate matter did exceed state standards in 1973. While the city of San Francisco has low oxidant readings, maximum one hour oxidant concentration approached or exceeded the health advisory alert level in Alameda, Contra Costa, San Mateo, Solano and Santa Clara Counties, with the most severe oxidant levels recorded in Mountain View and San Jose where they reached the .30 ppm range.

The potential for the production of photochemical air pollution in the San Diego area results from frequent low inversions and an abundance of sunlight. San Diego weather is characterized by few clouds, light winds, and moderate temperature with small diurnal variations in the coastal plain. Stagnant conditions occur frequently in the inland valleys.

In terms of air quality, problems along the Pacific Coast areas of Southern California are most affected. With the absence of major urban developments along the coast of California and the physical features of the land, the chances for problems resulting from offshore oil and gas operations remain small. The areas of Oregon and Washington are similar to those found along the majority of the California coast and do not represent any problems.

(3) Dredging

Dredging is a process commonly used along the entire length of the Pacific Coast to keep harbors open and to increase the depth of navigatable channels. Dredging produces a large quantity of spoil which is potentially dangerous to the environment since its redeposition can adversely effect the biota. Silt and clay are the primary deleterious grain sizes.

Special areas are designated for the dumping of dredge spoil. Spoil with silt and clay components is best disposed of on land. However, this is not always possible. Hence, a number of offshore sites are designated as acceptable for dredge spoil disposal by the Environmental Protection Agency. There are twelve approved disposal sites in northern California, and five sites in southern California. Similar sites are present off Washington and Oregon, although the number was not obtained.

4. Alaska Region (and Sub-Areas)

a. Geology

The geology of the nearshore and coastal zone has been described in the discussion of the offshore environment (section II A 4 a). This was done to present a complete and continuous description. Unlike biological and some physical parameters, geologic structures are not commonly distinguished according to an arbitrary division based on water depth or proximity to the shoreline. Where specific geologic structures are unique to a nearshore area, they are noted as such.

b. Biological Environment and Communities of the Coastal Zone

Alaska's coastline is long, diverse and complex. The general coastline is about 6,500 miles long (54% of the total 12,000 mile coastline of the U.S.). The tidal shoreline is greatest in the southeast region where the coast is a labyrinth of fiords, islands, bays, and rocks. The arctic shoreline is composed of a series of lagoons and barrier beaches.

The coast of Alaska covers a broad range in latitude and longitude, and includes ecosystems grading from temperate to extreme arctic. The arctic coast system is unique to Alaska. Associated with the arctic coast are biological communities found on and under the ice. These communities have been discussed previously in the Biological Environment (Section II A4d).

The biological environment of Alaska's coastlines is very poorly known. Fortunately, however, there is a considerable overlap of species and genera along the North Pacific coast from California to Alaska. Therefore, out-of-state references are useful to some extent, particularly in the Gulf of Alaska where faunal assemblages very closely resemble those of the Pacific Coast region discussed previously (Section IIB3b). Many other aspects of the coastal region have been covered in The Biological Environment of Alaska (Section IIA4d).

The most extensive research in the Alaska intertidal zone has been done for Prince William Sound, Amchitka, and Kodiak Island. These studies were conducted to examine the effects of the Alaskan earthquake in 1964 (Prince William Sound and Kodiak) and massive nuclear explosions (Amchitka). These studies were quantitative, but did provide additional toxonomic knowledge. In general, flora and fauna in the three areas were grouped into three major zones depending on the local tide range and wave heights. These studies have been briefly summarized by Feder and Mueller (1973) who also suggest areas of biological research which are in need of study (ecological relationships, dominant community members, etc.) in the Gulf of Alaska.

Despite the lack of detailed ecological studies of the Alaskan coastline, some impression of the diversity of shoreline communities can be obtained from an inventory of ecosystems as outlined by McRoy, et al. (1969). Figure 120 illustrates six biological regions in coastal Alaska, each designated by a number. Ecosystems within each of the regions are listed in Table 65 with representative locations. Those areas in the Gulf of Alaska exhibit nearly twice as many ecosystems as the Arctic Ocean shoreline, although the latter area has no man-induced stresses listed (sewage wastes, paper mill wastes, etc.).

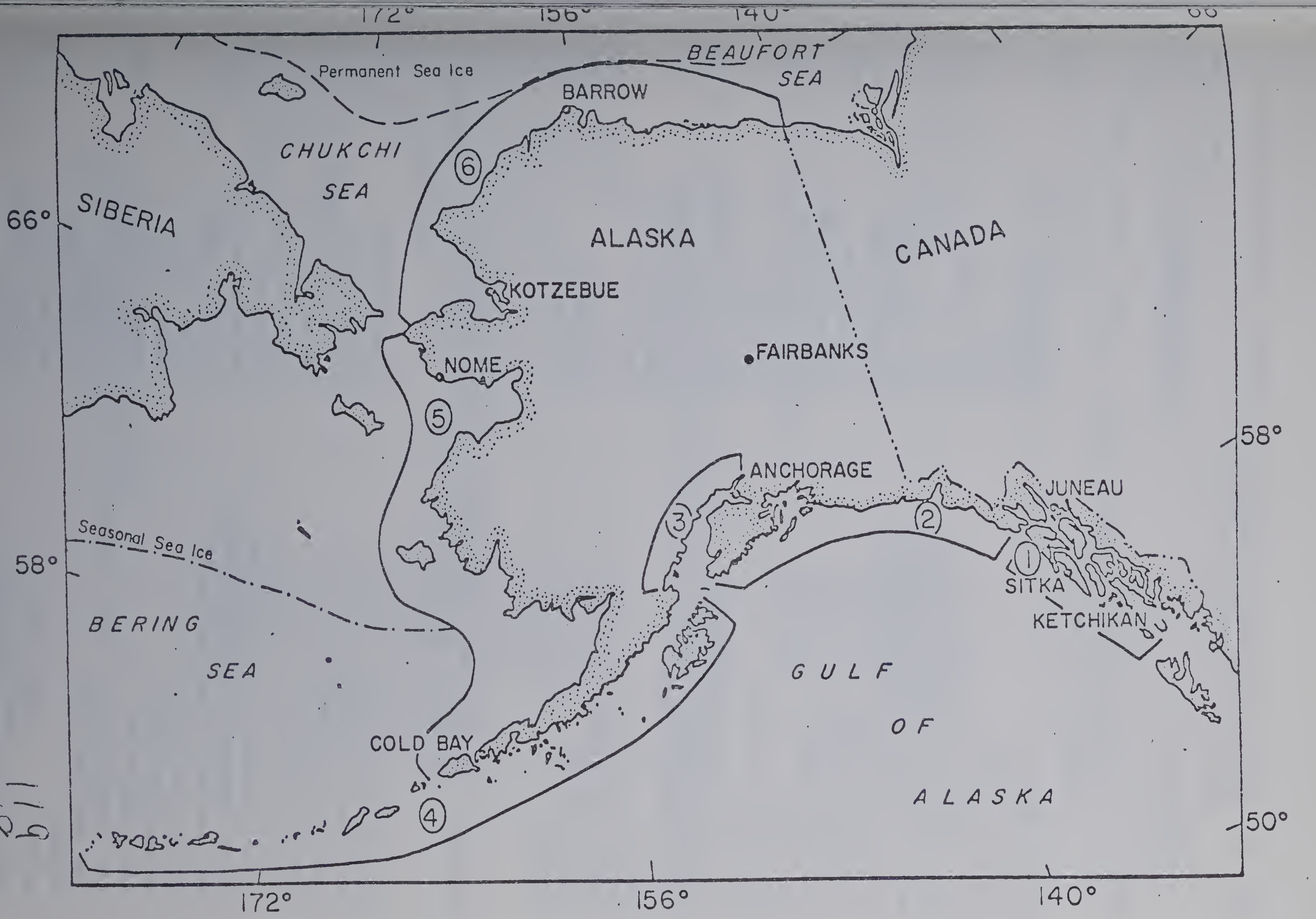


Fig. 120. Map of Alaska. Numerals refer to regions described in Table 1.

Table 65. Coastal ecosystems in Alaska with example locations (listed in approximate order of importance).

Region 1. Southeast Alaska
Estimated miles of tidal shoreline = 30,000 = 63% of Alaska
Number of types = 21

Types Found	Example Location
Glacial Fiords	Glacier Bay
Turbidity Fiords	Glacier Bay
Rocky Sea Fronts	Sitka
High Velocity Channels	Peril Strait
Medium Salinity Plankton Estuary	Auke Bay
Neutral Embayment and Shore Waters	Sea Otter Sound
Sheltered and Stratified Estuary	Port Frederick
Oligohaline System	Stikine River
Sedimentary Delta	Stikine River
Intertidal Rocks	Pleasant Island
Tide Pools	Pleasant Island
Worm and Clam Flats	Icy Strait
Kelp Beds	Icy Strait
Migrating Subsystem (salmon)	Little Port Walter
Eelgrass and Benthic Algae	Klawak
Bird and Mammal Rocks	Forrester Island
Marshes	Mendenhall Flats
Sewage Wastes	Juneau
Paper Mill Wastes	Silver Bay
Seafood Wastes	Petersburg
Pilings	Ketchikan

Region 2. Pacific Coast, Cape Spencer to Cape Elizabeth
Estimated miles of tidal shoreline = 6,500 = 14% of Alaska
Number of types = 22

Types Found	Example Location
High Energy Beaches	Cape Suckling
Rocky Sea Fronts	Granite Cape
High Velocity Channels	Bainbridge Passage
Glacial Fiords	Unakwik Inlet
Turbidity Fiords	Columbia Glacier
Medium Salinity Plankton Estuary	Valdez Arm
Neutral Embayment and Shore Waters	Montague Strait
Sheltered and Stratified Estuary	College Fiord
Oligohaline System	Copper River
Sedimentary Delta	Copper River
Intertidal Rocks	Montague Island
Tide Pools	Montague Island
Worm and Clam Flats	Orca Inlet
Eelgrass	Redhead Lagoon
Marshes	Redhead Lagoon
Kelp Beds	Montague Island
Migrating Subsystem (salmon)	Olsen Bay
Bird and Mammal Rocks	Montague Island

Sewage Waste	Cordova
Seafood Waste	Seward
Multiple Stress (earthquake) Beach	Montague Island
Pilings	Valdez

Region 3. Cook Inlet
Estimated miles of tidal shoreline = 400 to 500 = 1% of Alaska
Number of types = 9

High Velocity Channel	Forelands
Sedimentary Delta	Knik Arm
Oligohaline System	Turnagain Arm
Worm and Clam Flats	Cook Inlet
Migrating Subsystem (salmon)	Kachemak Bay
Sewage	Anchorage
Petroleum Shores	Kalgin Island
Pilings	Anchorage
Multiple Stress (ice, oil, tides)	Cook Inlet

Region 4. Kodiak Island, Alaska Peninsula, and Aleutian Islands
Estimated miles of tidal shoreline = 1500 x 5 = 7500 = 16% of Alaska
Number of types = 18

Rocky Sea Fronts	Aleutian Islands
Bird and Mammal Rocks	Amak Island
High Energy	Unimak Bite
High Velocity Channel	Unimak Pass
Neutral Embayment and Shore Waters	Cold Bay
Medium Salinity Plankton Estuary	Kitoi Bay
Sheltered and Stratified Estuary	Kodiak Island
Migrating Subsystem (salmon)	Cold Bay
Worm and Clam Flats	Cold Bay
Kelp Beds	Shumagin Islands
Eelgrass	Kinzarof Lagoon
Marshes	Kinzarof Lagoon
Intertidal Rocks	Aleutian Islands
Tide Pools	Aleutian Islands
Seafood Waste	Kodiak
Petroleum Shores	Amchitka
Pilings	Kodiak
Radioactive Stress	Amchitka

Region 5. Bristol Bay to Bering Strait
Estimated miles of tidal shoreline = 1800 = 4% of Alaska
Number of types = 14

High Energy Beaches	Kudiakof Island
Sedimentary Delta	Yukon Kuskokwim
Oligohaline System	Yukon Kuskokwim
Migrating Subsystems (salmon, birds)	Bristol Bay

Eelgrass	Izembek Lagoon
Medium Salinity Plankton Estuary	Kvichak Bay
Ice Stress Coast	Norton Sound
Under Ice Plankton	N. Bering Sea
Marshes	Izembek Lagoon
Worm and Clam Flats	Izembek Lagoon
Bird and Mammal Rocks	Pribilof Islands
Seafood Wastes	Port Moller
Sewage	Nome
Dredgings	Norton Sound

Region 6. Bering Straits to Canadian Border
Estimated miles of tidal shoreline = 1000 = 2% of Alaska
Number of types = 13

Ice Stressed Beaches	Elson Lagoon
Sea Ice and Under Ice Plankton	Arctic Ocean
High Energy Beaches	Pt. Barrow
Multiple Stress Beaches (ice, light, salinity)	Kasegaluk Lagoon
Oligohaline System	Kotzebue Sound
Sedimentary Delta	Colville River
Bird and Mammal Rocks	Cape Thompson
Worm and Clam Flats	Kotzebue Sound
Sewage	Kotzebue
Marshes	Selawik Lake
Eelgrass	Shishmaref
Kelp Beds	Wainwright
Radioactive Stress	Kotzebue Sound

Intertidal fauna of the Bering Sea is very poorly known, perhaps due to the lack of commercial development of the area. The estuaries and lagoons of Bristol Bay have received some attention. Malick, et al. (1971) noted that worms and clams were the dominant invertebrates in soft mud substrates.

North of Bristol Bay, ice plays an important role in intertidal development. According to Menzies, et al. (1973), ice cover, ice scour, and ice grinding generally make the arctic intertidal zones inhospitable to colonization by forms that are intertidal elsewhere.

The first major American study of arctic biology in the coastal zone was done by MacGinitie (1955) at Point Barrow. Although he did not determine the dominant species of the community, he found 428 species of animals in the zone from 0 to 65 meters. The intertidal region was barren, but MacGinitie found the region below ice cover to be populated with those organisms shown in Table 66.

Zenkevitch (1963) found the effects of ice diminished rapidly below about 10 meters. Below this depth the biological communities were comparable to shallow seas. Table 67 lists the biomass and relative proportion of invertebrate groups living under the ice cover. Table 68 lists the macrophyte

Table 66. Sublittoral invertebrates in order of relative abundance on soft bottoms near Point Barrow (from MacGinitie, 1955).

I. Infauna of Nearshore Mud Zone:
Echiurus echiurus alaskanus (echiuroid worm)
Arenicola glacialis (polychaete)
Myriotrochus rinki (sea cucumber)
Antinoe sarsi (polychaete)
Melaenis lovenis (polychaete)
Harmothoe imbricata (polychaete)
Hamingia arctica (echiuroid worm)
Halicryptus spinulosus (priapulid worm)
Burrowing anemones (2 species)
Burrowing tunicates (2 species)
Mya truncata (clam)
Mya japonica (clam)

II. Infauna of Outer Shore Mud Zone:
Cerianthus sp. (burrowing anemone)
Macoma calcarea (clam)
Astarte montaqui (clam)
Myriotrochus rinki (burrowing sea cucumber)
Nucula tenuis (clam)

III. Epifauna of the Mud Zone:
Foraminifera
Dulichia porrecta (amphipod)
Pagurus splendescens (hermit crab)
Pagurus trigonocheirus (hermit crab)
Hyas coarctatus alutaceus (crab)
Serripes groenlandicus (clam)
Liocyma fluctosa (clam)

Table 67 Biomass of sublittoral benthic invertebrate groups on the Siberian coast of the Chukchi Sea (from Zenkevitch, 1963).

Invertebrate Group	Biomass g/m^2	Relative Proportions
Polychaetes	35.2	16%
Crustaceans	31.8	15%
Echinoderms	16.2	7%
Gastropods	2.0	1%
Lamellibranchs	114.6	53%
Others	14.4	7%
Total	214.2	

Table 68 Macrophyte algae collected from kelp bed on arctic coast of Alaska (from Mohr *et al.*, 1957).

Brown Algae

Phyllaria dermatodea
Lominaria saccharina
Desmarestia viridis

Red Algae

Turnerella pennyi
Phytilophora interrupta
Antithamnion americanum
Phycodrys sinuosa
Polysiphonia arctica
Odonthalia dentata
Rhodomela lycopodioides f. flagellaris

algae from a kelp bed in the arctic coast. Because algae apparently can survive very low temperatures, the greatest hazard to the marine plants is the scouring by ice rather than the cold temperatures. Zenkevitch (1963) cited the lack of a hard substrate for attachment as the most crucial factor restricting the distribution of macrophytes in Arctic Alaska.

c. Resources of the Coastal Zone

(1) Land Uses

Of the 47,300 miles of Alaska coastline, less than 1 percent (300 miles) is considered developed.

Coastal Alaska communities account for 61 percent of the State's total population. The Cook Inlet-Resurrection Bay Area has 49 percent of the population; 39 percent reside in the eastern Gulf of Alaska coastal areas, southeastern and interior Alaska; and 13 percent in the Arctic Coast, northwestern and western Alaska, Bristol Bay and the Aleutian Islands. (U.S.B.C., 1971)

Land use varies in intensity and type from one coastal region to another.

Land use in the northern, western, southwestern and Aleutian Coasts is essentially limited to subsistence hunting, fishing and gathering from both marine and terrestial systems. Most villages are small ranging in size from less than 100 inhabitants to maximums usually less than 500.

Land use in the Cook Inlet-Resurrection Bay area is by far the most intensive of all coastal Alaska. Uses are similar to that found in any metropolitan area of 150 to 200 thousand. Current oil and gas production in the area totals 200,000 bbl./day of oil and 224,000,000 MCF of gas in all of 1973. Yet there are vast open spaces which permit the existence of natural resource based endeavors including timber industry, mining, commercial fishing (harbors and canneries), agriculture and outdoor recreation. These industries face increasing competition from urban sprawl and concomitant land requirements of the support sector of the economy on which the natural resource industries depend.

Land use in the eastern and central Gulf of Alaska coast is restricted generally to the fishing and timber industries.

Ownership of much of the coastal area of Alaska is in a state of flux. Redistribution of ownership is underway under the provisions of the Alaska Statehood Act (P.L. 85-508) and the Alaska Native Claims Settlement Act (ANCSA) (P.L. 92-203) It appears that a very small portion of the coastline will be in private ownership other than Native (Eskimo, Aleut, Indian). Pending the establishment of entitlement under ANCSA the ownership of long stretches of coastline may be in doubt. Further limiting the availability of land for general purposes are withdrawals such as National Wildlife Refuges and Ranges, National Forests, and the Naval Petroleum Reserves, and National Parks and Monuments.

(2) Recreation Resources

The diversity of recreation opportunities makes the coastal zone of Alaska very important from a recreation viewpoint.

The main attraction to Alaskan visitors is the undeveloped wild and rugged wilderness that this region possesses.

The numerous lakes, streams and ocean fisheries in the coastal zone provide some of the best sport fishing available. All five species of the North American salmon, sea run Dolly Varden and steelhead trout are among the species of fish that can be taken by the sport angler.

Hunting opportunities are numerous with brown/grizzly bear taken throughout the coastal zone, and the famous Kodiak bear on Kodiak Island. The Sitka blacktail deer is hunted in the Prince William Sound area and in southeast Alaska and Kodiak. Many species of ducks and geese are also available.

Sightseeing opportunities are varied and numerous. Many high quality scenic areas exist along the coastline and surrounding mountains. Geological features of interest include, volcanos, glaciers and fiords. Zoological features include a rich variety of bird life, many seabird colonies and many concentrations of sea otter, sea lions and seals. Prehistoric and historic native sites, old gold camps and Russian churches are present which depicts Alaska's rich cultural past.

The rivers, lakes and protected marine water in the coastal zone provide good opportunity for powerboating, float boating, canoeing and sailboating.

The two national forests, 18 national wildlife refuges and one national monument give the coastal zone of Alaska national recognition from a recreation standpoint.

During the 1973 recreation season there were approximately 11 million visits to federal, state and local government operated recreation areas in Alaska (Figures 121-123). The number of tourists who visited Alaska during this time was 215,000 (Alaska Division of Parks 1973). Because of limited access and population distribution in Alaska, the majority of these recreation and tourist visitors would at one time or another spend time in the coastal zone of Alaska.

An inventory of lands dedicated for recreation and recreation facility capacity are shown on Figure 124.

REGIONAL DISTRIBUTION OF
VISITATION TO LOCALLY
OPERATED AREAS DURING FY 1973

STATEWIDE = 2,428,675

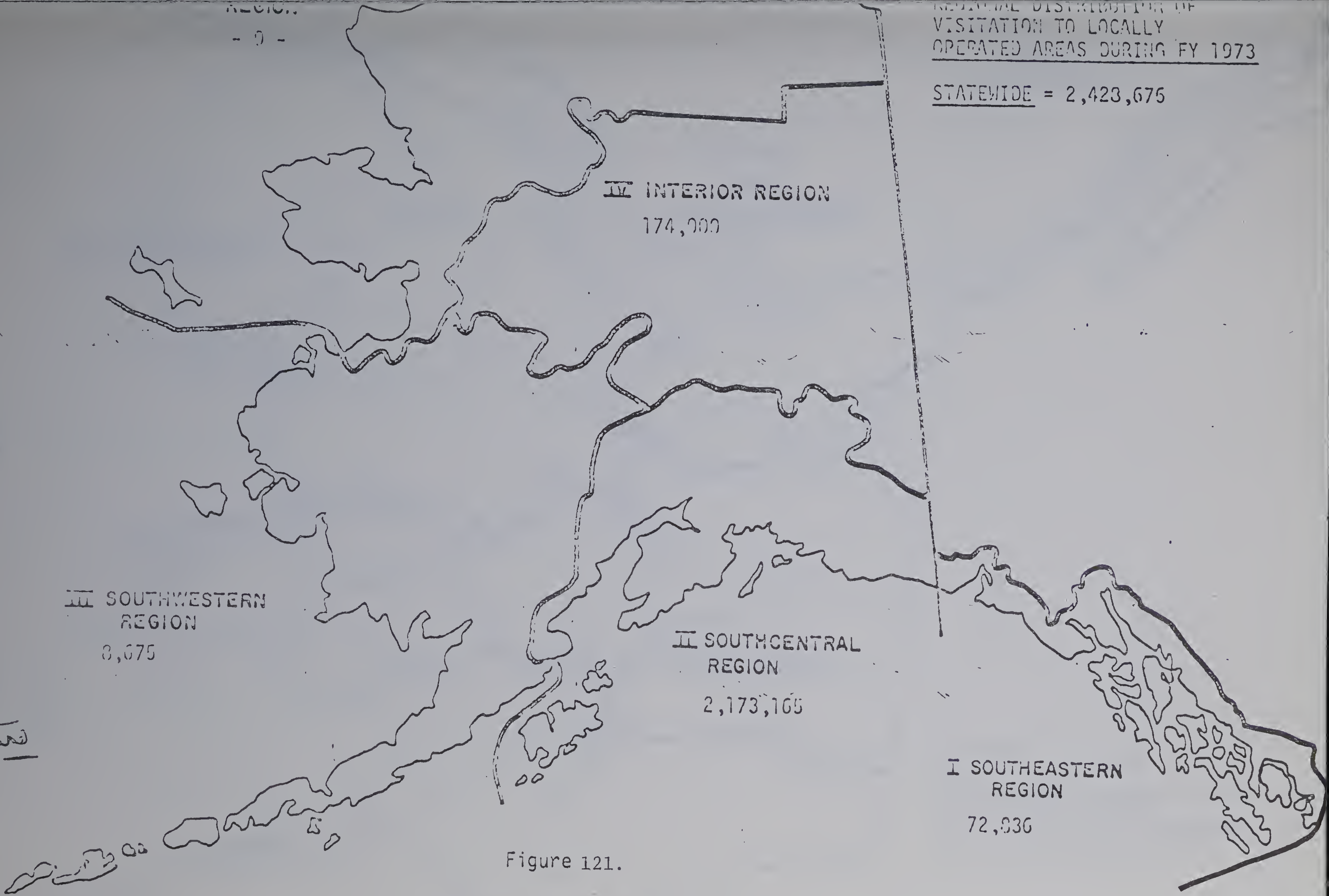
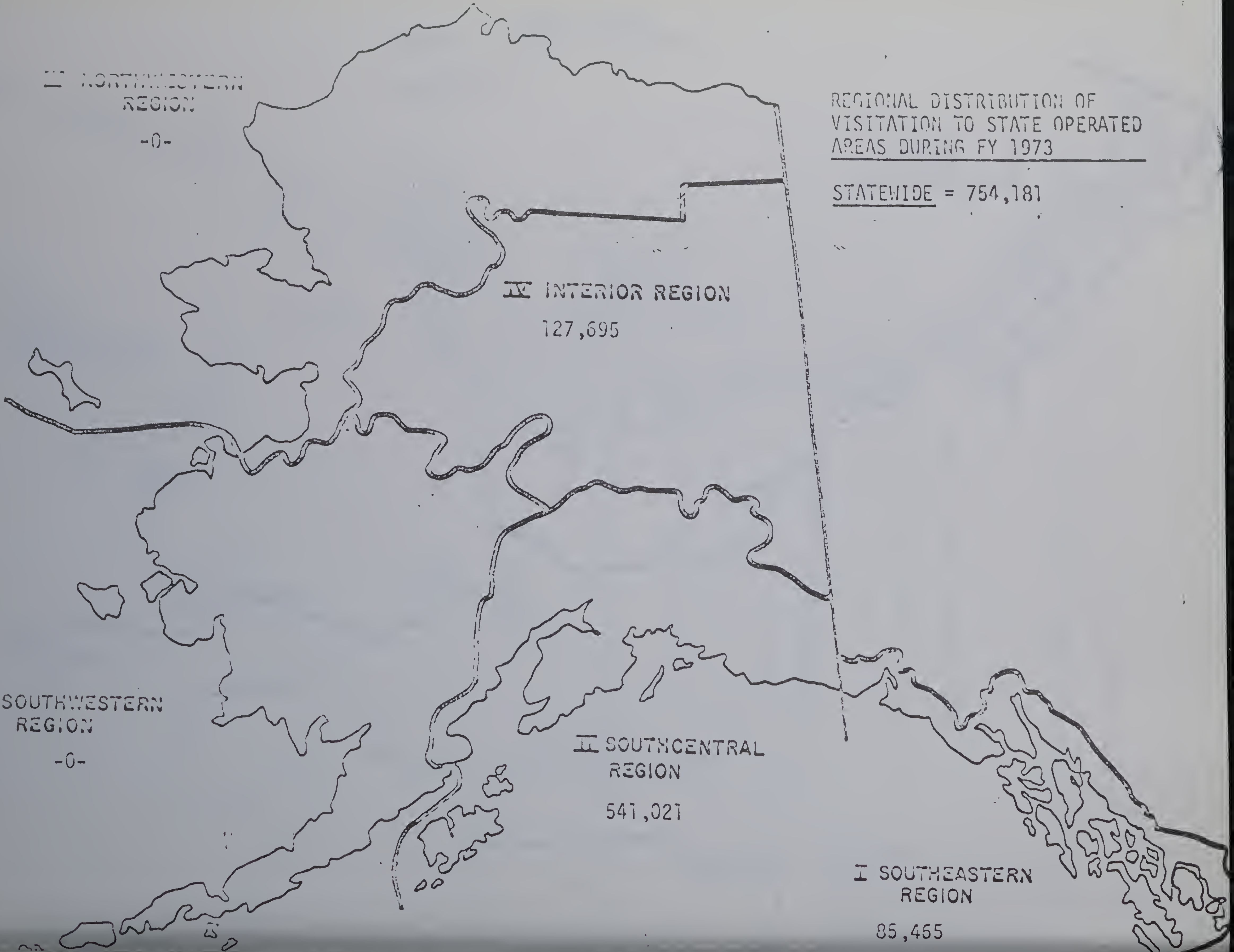


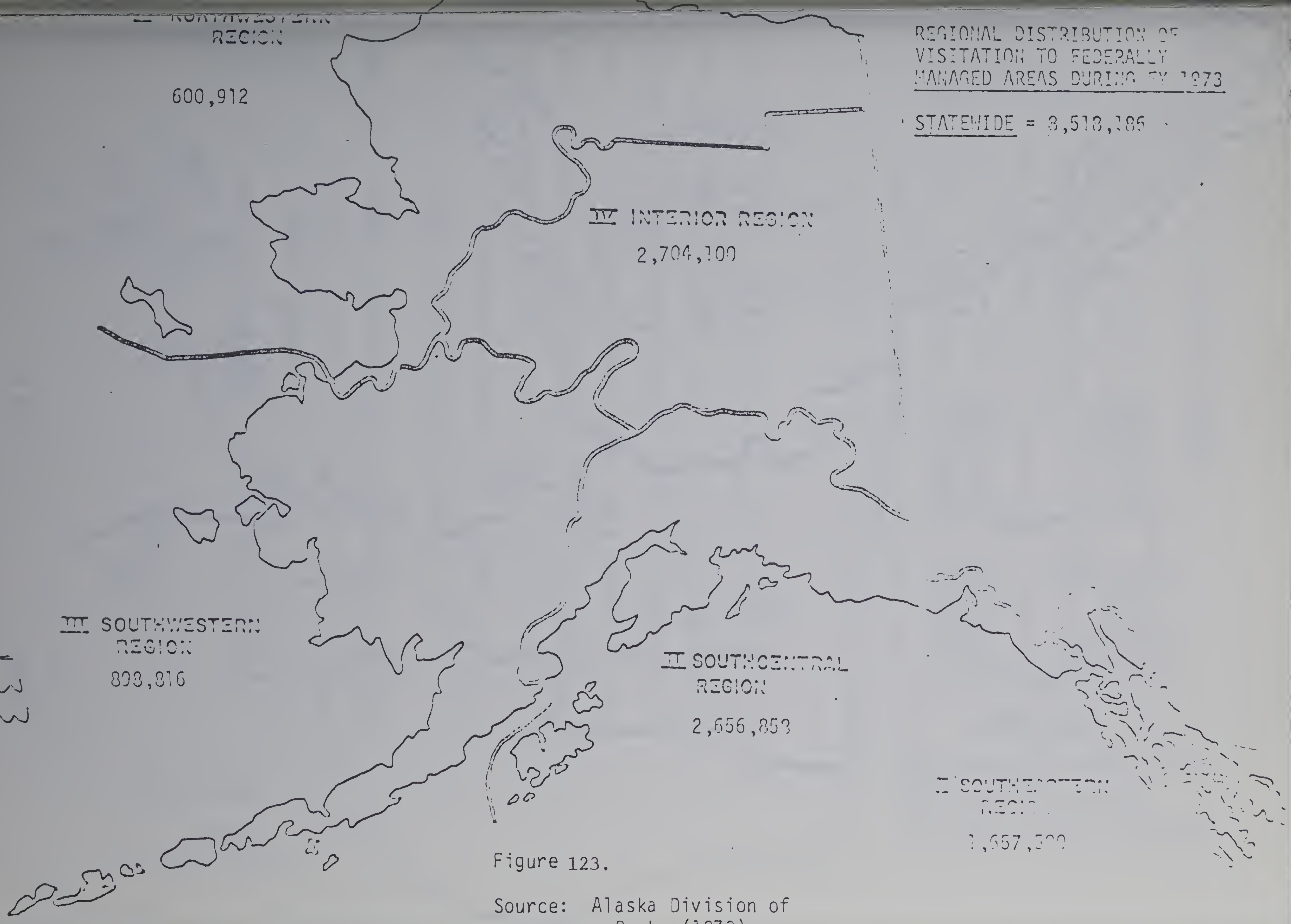
Figure 121.

Source: Alaska Division of
Parks (1973)



REGIONAL DISTRIBUTION OF VISITATION TO STATE OPERATED AREAS DURING FY 1973

STATEWIDE = 754,181



REGIONAL DISTRIBUTION OF VISITATION TO FEDERALLY MANAGED AREAS DURING FY 1973

STATEWIDE = 8,518,186

Figure 123.

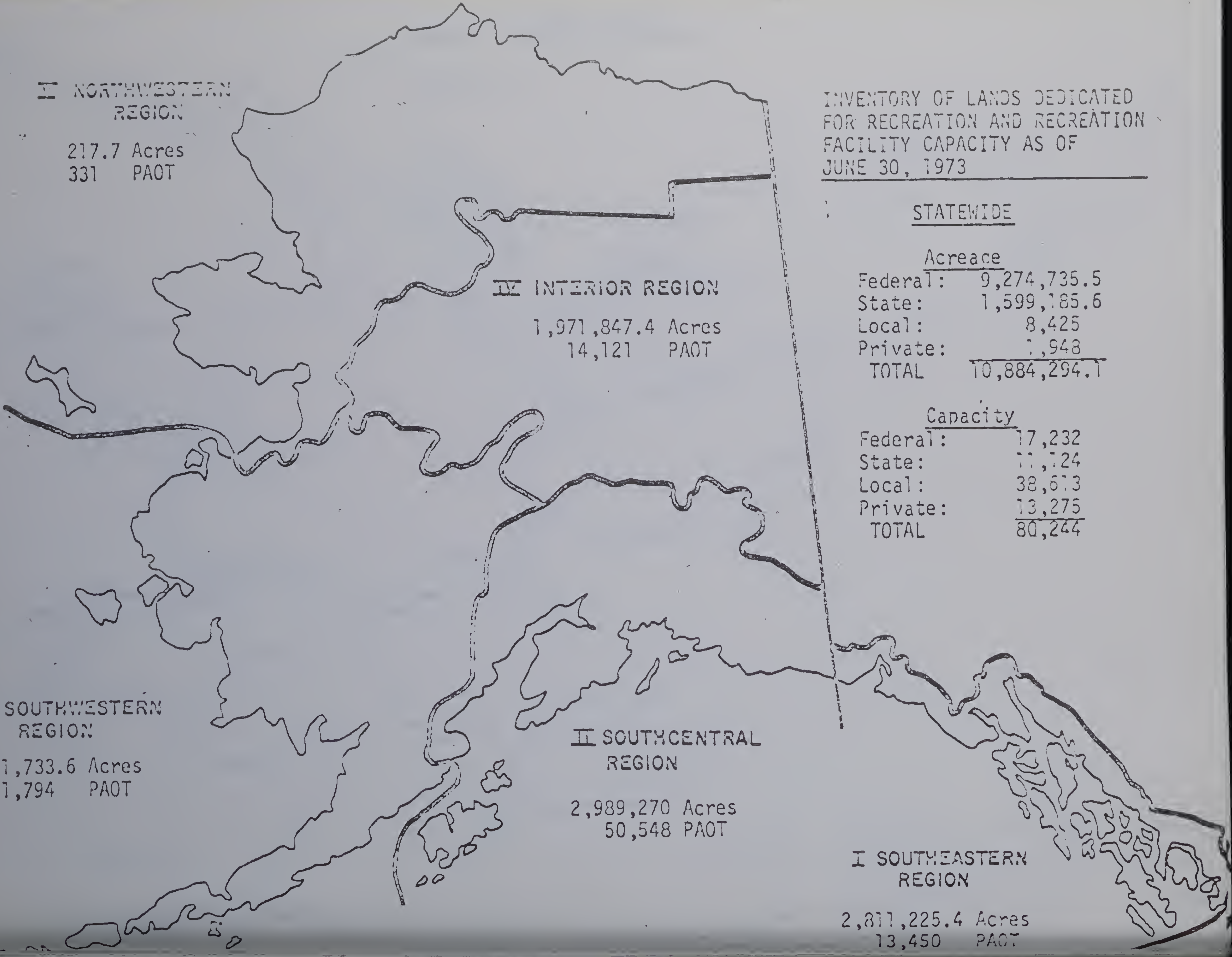
Source: Alaska Division of Parks (1973).

INVENTORY OF LANDS DEDICATED FOR RECREATION AND RECREATION FACILITY CAPACITY AS OF JUNE 30, 1973

STATEWIDE

Acreace	
Federal:	9,274,735.5
State:	1,599,185.6
Local:	8,425
Private:	1,948
TOTAL	10,884,294.1

Capacity	
Federal:	17,232
State:	11,124
Local:	38,613
Private:	13,275
TOTAL	80,244



(3) Ports and Shipping

Waterborne commerce within, to, or from Alaska amounted to slightly over 23.5 million short tons in 1971, representing substantial annual increases over the 4.7 million short tons moved in 1959 (Alaska Statistical Review 1972). Although the increase has been rapid, its useful to compare the tonnage to that of other areas, e.g., Long Beach and Ventura, California together had as much (98%+) waterborne commerce as did the entire state of Alaska in 1972 (U.S. Army Corps of Engineers, 1972).

Employment in water transportation has declined significantly over the years, owing to greater capital intensiveness and general changes in the composition of market demand for transportation services. In 1960, 1.5 thousand workers were employed in some facet of waterborne transportation; by 1971, this number had decreased to 800. In 1960, water transportation accounted for 30% of total transportation employment and dropped to less than 14% in 1971 (Alaska Statistical Review 1972).

Over 50% of Alaska waterborne commerce is petroleum products. Of this, 56% (8.3 milion tons) is crude oil from the Cook Inlet. Additionally, about 7% of non-crude petroleum products are accounted for by the liquified natural gas (LNG) plant which exports its product from Cook Inlet to Japan.

Tables 69 and 70 summarize the passenger and freight traffic for 1972, as well as harbor usage by 20"+ draft vessels and inbound tankers. The number of inbound vessels is slightly greater than outbound number because backhaul loads are sometimes not available and empty vessels are not counted.

The impact on ports and shipping that results from development of any of the OCS districts except Cook Inlet will necessarily be significant for several reasons. First, virtually all crude and LNG is currently shipped from Cook Inlet; hence were the operations to take place elsewhere, there would certainly be effects from additional traffic, residual spills and the likelihood of major spills. Secondly, competition for services and berthing space for smaller boats would probably increase, forcing current users to incur greater costs assuming they would still require the services or facilities. Third, depending upon the density of structures and vessels associated with the development, the impact could also be felt by commercial fishermen by limiting the open space for movement and crowding existing traffic lanes.

TABLE 69

Port and Shipping Data - 1972

Major** Harbor	Controlling Depth (MLLW)	Psngrs.	1972 - Freight Thousand Short Tons
Metlakatla	25 ft.		291,331
Ketchikan	Adequate - 15 ft.	42,249	2,186,282
Wrangell	10 ft.	15,890	1,169,203
Wrangell Narrows	24-26 ft.	-	1,003,453
Sitka	22 ft.	11,147	1,243,437
Skagway	Adequate - 19 ft.	70,718	1,387,562
Valdez	20-50 ft.	-	253,505
Anchorage	28-35 ft.	2,342	2,058,199
Other Harbors			
Homer		7,052	170,382
Iliuliuk			190,109
Juneau		57,810	200,529
Kodiak		9,717	192,963
Petersburg		16,718	157,809
Other Southeastern		60,010	
Alaska Peninsula (South side)		632	12,399,786
Whittier		18,833	646,609
		313,118	23,551,159

**Includes only those harbors receiving 100,000 tons and over annually
*Source: Waterborne Commerce of the U.S. - 1972
U.S. Army Corps of Engineers, Part 4

TABLE 70

Harbor Usage by 20'+ Draft Vessels - 1972

	Total	Tanker (Inbound)
Metlakatla	9	0
Ketchikan	55	40
Wrangell	41	0
Sitka	38	9
Skagway	147	4
Valdez	39	25
Anchorage	160	69

*Source: Waterborne Commerce of the U.S. - 1972
U.S. Army Corps of Engineers, part 4

Other Transportation

Air. Air transportation has employed more persons than any other type of transportation in the State. Average monthly employment in air transportation grew from 1,800 in 1959 (38 percent of total transportation employment) to 2,800 in 1971 (45 percent). It rose 55 percent over the thirteen year period, averaging almost 7.2 percent growth per year over the last half of the period. Increased North Slope activity was responsible for much of the huge jump (24 percent) in air employment from 1968 to 1969 since employment in this sector nearly doubled in the Fairbanks area. Since 1969, air transportation employment has declined reflecting the reduction in activity north of Fairbanks.

Compared to the total population of the United States, Alaskans are exceedingly engaged in flying. On a per capita basis, Alaska has four and one-half times the number of lincensed pilots as does the U.S. The number of eligible aircraft registered with the FAA in the State has grown steadily since statehood and topped 2,200 in 1970.

The preponderance of air operations and air carrier activity in Alaska emphasizes the underdeveloped status of other modes of transportation. Air transportation requires a relatively minor capital investment to provide reliable transportation services.

The operating costs of air transportation are relatively high, though, and the overall cost of air transportation tends to be higher than that of other modes when substantial quantities are moved. As alternate methods of transportation develop in Alaska, the predominant role of air transportation may tend to decrease. This is not to say that air activity itself will decrease. Air carriers will retain business where time-in-transit is of substantial importance (primarily, passengers and certain types of freight).

Rail. There are two railroads in Alaska--the Alaska Railroad (ARR) and the White Pass and Yukon Route (WP & YR). The ARR, built over the period 1914 to 1923, is owned by the Federal Government and operated under the Department of Transportation. The railroad extends from Seward north to Fairbanks, in the Interior, passing through Anchorage, Mt. McKinley National Park, and a number of stations and towns along the way. Branches serve the agricultural area in the Matanuska Valley and the coal fields in the Healy River area approximately 100 miles south of Fairbanks. An additional spur connects the Port of Whittier on Prince William Sound. The WP & YR, owned by a Canadian corporation, has a terminal facility at Skagway, Alaska, and serves Whitehorse, Yukon Territory, and certain mining facilities in the Yukon. (State of Alaska. Department of Economic Development. 1972).

Surface Transportation. The greater part of Alaska's Highway system is in the central and southcentral part of the State, roughly following the "railbelt" that was established earlier in the century. The highway system connects Alaska-Canadian Highway built as a result of World War II; in addition, the barge and ferry system provides a water-linked intertie for West Coast originating traffic.

While the highway system serves the greater part of Alaska's population, it exists in only a few of the State's geographic regions. The absence of landed surface transportation systems in Southeastern Alaska is due mostly to topography. The sparse population appears to be the principal deterrent for road systems in the Northern, Northwestern, Western and Southwestern regions of the State.

(4) Commercial Fisheries

The value of Alaska's 1973 commercial fisheries landings ($162,084,000) was larger than any other state (U. S. Dept. of Comm., 1974). Next to petroleum products, fisheries are Alaska's greatest source of revenue. Because of the size and history of Alaska's fisheries, a high level of public passion exists within the state regarding all aspects of fisheries policy.

A great potential for fisheries development exists in Alaska. In spite of the tremendous value of Alaskan fishery landings, foreign catches in oceans adjacent to Alaska are nearly ten times as great (poundage) as American catches. Ships of three countries (Russia, Japan, and South Korea) dominate these foreign fleets. These fleets concentrate in the Bering Sea catching herring, bottom fish (flounders, halibut), crabs (tanner and king), some demersal fish (Pacific Ocean perch, sablefish), and salmon.

Species of commercial fishes have already been discussed in a previous Section (Active swimmers - Nekton, II A 4 d (4)), as to their relative abundance and value. Table 71 presents the catch weight and value to fishermen in 1971 by regions. The regions are 1) Southeastern region, which includes the ports of Ketchikan, Petersburg - Wrangell, Sitka, and Juneau - Yakutat; 2) Central region, including the ports of Copper - Bering Rivers, Prince William Sound, Resurrection Bay, Cook Inlet, Kodiak, Chignik, and those of the south peninsula; Western region, including the Aleutian Islands, north peninsula, Bristol Bay, and the Artic - Yukon. The dominance of salmon, in weight and value, is obvious from the table.

Table 71

1971 Catch and Value to Fishermen, by Region
From A.D.F. and G., 1974

	SOUTHEASTERN		CENTRAL	
CIES	Pounds	Value	Pounds	Value
mon:				
ing or Chinook	4,528,834	$ 2,976,194	1,062,772	$ 389,560
ed or Sockeye	3,967,147	1,418,826	23,795,979	6,053,327
oho or Silver	7,136,576	1,928,614	4,013,394	845,094
ink or Humpback	34,414,077	5,231,120	51,702,552	8,270,327
hum or Dog	16,095,008	2,536,503	29,282,200	3,906,834
OTAL SALMON	66,141,642	14,091,257	109,856,897	19,465,142
ibut	10,015,771	$ 2,970,061	13,894,996	$ 4,266,751
ring	5,983,333	111,626	4,134,151	157,824
ring eggs on kelp	--	--	769,481	384,741
lefish	573,472	95,160	21,345	3,223
elhead Trout	15,601	4,227	57	14
tom Fish	95,905	$ 11,162	186,227	$ 27,211
her Fish	42,512	6,310	881	243
AL MISC. FISH	16,726,594	3,198,546	19,007,138	4,840,007
AL FISH	82,868,236	$ 17,289,803	128,864,035	$ 24,305,149
ab:				
ing	571,062	$ 198,046	20,220,631	$ 5,902,239
ungeness	1,668,654	272,796	2,064,579	334,698
anner	251,082	25,108	12,463,005	1,326,833
cimp	959,787	95,245	93,931,517	3,813,800
ams	--	--	243,121	70,152
allops, shucked	84,948	84,948	846,203	905,437
alone	923	2,077	--	--
AL SHELLFISH	3,536,456	$ 678,220	129,769,056	$ 12,353,159
AND TOTAL	86,404,692	$ 17,968,023	258,633,091	$ 36,658,308

Table 71, cont.

SPECIES	WESTERN Pounds	 Value	TOTAL (all three Pounds	 Va
Salmon:				
King or Chinook	6,380,288	$ 1,322,568	11,971,894	$ 4,68,
Red or Sockeye	59,524,528	15,376,574	87,287,654	22,88,
Coho or Silver	309,447	46,435	11,459,417	2,80,
Pink or Humpback	143,138	16,407	86,259,767	13,57,
Chum or Dog	9,349,112	1,093,045	54,726,320	7,56,
TOTAL SALMON	75,706,513	$ 17,855,029	251,705,052	$ 51,41,
Halibut	--	$ --	23,910,767	$ 7,26,
Herring			10,117,484	29,
Herring eggs on kelp	51,795	5,180	821,276	39,
Sablefish	1,464	220	596,281	8,
Steelhead Trout	--	--	15,658	4,
Bottom Fish	--	$ --	282,132	$ 8,
Other Fish	79,839	22,559	123,232	9,
TOTAL MISC. FISH	133,098	$ 27,959	35,866,830	$ 8,06,
TOTAL FISH	75,839,611	$ 17,882,988	287,571,882	$ 59,47,
Crab:				
King	49,911,412	$ 12,976,968	70,703,105	$ 19,07,
Dungeness	16,196	2,430	3,749,429	69,
Tanner	166,037	16,603	12,880,124	1,38,
Shrimp	--	--	94,891,304	3,99,
Clams	--	--	243,121	0,
Scallops, shucked	--	--	931,151	90,
Abalone	--	--	923	2,
TOTAL SHELLFISH	50,093,645	$ 12,996,001	183,399,157	$ 26,07,
GRAND TOTAL	125,933,256	$ 30,878,989	470,971,039	$ 85,55,

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(5) Oil and Gas Resources

The following estimates of oil and gas resources are provided by U.S. Geological Survey. USGS emphasizes that the estimates are speculative; only the maximum credible expectations are shown.

TABLE 72: Measured and Inferred Reserves, 0-200 meter water depth. (12-31-72).
(Oil in billions of barrels and includes natural gas liquids)
(Gas in trillions of cubic feet)

Area	Measured Reserves		Inferred Reserves	
	Oil	Gas	Oil	Gas
Gulf of Alaska	0	0	0	0
Cook Inlet	0.7	1.8	0-0.5	1-1.5
Aleutian Shelf	0	0	0	0
Bristol Basin	0	0	0	0
Bering Sea	0	0	0	0
Chukchi Sea	0	0	0	0
Beaufort Sea	0	0	0	0

TABLE 73: Estimates of undiscovered recoverable resources, 0-200 meters water depth. [1]/
(Oil in billions of barrels and includes natural gas liquids)
(Gas in trillion of cubic feet)

Area	Estimated undiscovered recoverable resources	
	Oil	Gas
Gulf of Alaska	0-20	0-100
Cook Inlet	0-10	0-50
Aleutian Shelf	0-5	0-25
Bristol Basin	0-10	0-50

---

[1]/ On March 26, 1974, the U.S. Geological Survey released estimates of the undiscovered recoverable oil and gas resources for broad areas of the OCS. Those estimates were based on statistical parameters of oil occurrences that apply only to broad geographic areas. It is entirely inappropriate to apply the same parameters to small, specific areas. The resource figures in the above table represent a general estimate, based on the above referenced table, of minimum and maximum volumes of oil and gas that might be recovered from the various OCS areas. It is statistically unsound to add the maxima and minima for an expectable range of resources for any larger area.

Area	Oil	Gas
Bering Sea	0-20	0-100
Chukchi Sea	0-10	0-50
Beaufort Sea	0-10	0-50

TABLE 74: Current (1972) oil and gas production from coastal State waters.
(Oil in billions of barrels and includes natural gas liquids)
(Gas in trillions of cubic feet)

	Oil and gas production (1972)	
Area	Oil	Gas
Gulf of Alaska	0	0
Cook Inlet	0.1	0.1
Aleutian Shelf	0	0
Bristol Basin	0	0
Bering Sea	0	0
Chukchi Sea	0	0
Beaufort Sea	0	0

TABLE 75a: Estimate of undiscovered recoverable resources in coastal State waters. 1/
(Oil in billions of barrels and includes natural gas liquids)
(Gas in trillions of cubic feet)

	Estimated undiscovered recoverable resources	
Area	Oil	Gas
Gulf of Alaska	0-2	0-10
Cook Inlet	0-1	0-5
Aleutian Shelf	0-1	0-5
Bristol Basin	0-1	0-5
Chukchi Sea	0-1	0-5
Beaufort Sea	0-2	0-10

TABLE 75b: Measured and inferred reserves, coastal State lands (12-31-72)
(Oil in billions of barrels and includes natural gas liquids)
(Gas in trillions of cubic feet)

1/ Ibid.

Area	Measured Reserves		Inferred Reserves	
	Oil	Gas	Oil	Gas
Gulf of Alaska	0	0	0	0
Cook Inlet	0.7	1.8	0-.5	1-1.5
Aleutian Shelf	0	0	0	0
Bristol Basin	0	0	0	0
Bering Sea	0	0	0	0
Chukchi Sea	0	0	0	0
Beaufort Sea	0	0	0	0

The 1973 production from upland wells in Alaska was 72,323 bbl. oil and 130,815 MCF of gas.

(6) Military Uses

There is extensive military use of the U.S. coastal shore areas. It is difficult to generalize about the varied military uses of these areas. Prior to granting leases in any coastal area the Department of Defense will designate the zones within the nominated area which are used for security, defense warning, or other military purposes. Negotiations with DOD and DOI will then follow.

(7) Historical and Projected Economic Growth

This discussion of the "Economic Overview" is taken directly from Alaska Statistical Review, 1972. State of Alaska, Department of Economic Development, Division of Economic Enterprise, page 3 and 4.

> "From statehood to 1971, Alaska's economy achieved substantial growth and development. Alaska Gross Product (analogous to GNP, but on the State level) jumped from less than $720-million in 1960 to over $2 billion in 1971. Employment grew by more than 75 percent from 62,900 in 1959 to 110,600 in 1971. Income more than doubled from $410 million in 1961 to almost $1.1 billion in 1971. Over the thirteen year period, Alaska became less dependent upon federal expenditures as new industries emerged and existing industries expanded their economic activities.
>
> "Since 1969, oil and natural gas have replaced fisheries as Alaska's leading industry. While the fish and shellfish catch fluctuates widely from year to year and from region to region, the value to the producer and to the fisherman has increased substantially in the last year. Forest products has posted very steady gains in production value over the decade ($118 million in 1971) but continues to lag behind petroleum ($286 million) and fisheries ($199 million) as Alaska's third major industry. Tourism growth has been very rapid, particularly since 1967. Since the impactis felt throughout the supportive industries, employment attributed directly to Alaskan tourism is difficult to identify and measure. The growth in minerals (excluding oil and gas) is attributed to growth in demand for sand and gravel. While this industry holds great potential, its current impact is negligible compared to the four leading industries. Agriculture has consistently contributed about $5.5 million to the State's economy.

> "Three occurrences appear to be largely responsible for the year-to-year changes in the State's economy. First, the continuous transfer of former federal functions to State authority was evidenced by the static, or slightly declining, level of federal employment and the rapid rise of State and local government employment. Second, the restoration activities from the 1964 earthquake brought an increase in construction activity in 1964 and 1965. Finally, the swift upsurge in oil activity appeared to provide much of the impetus to Alaska's economy in the late 1960's.
>
> "Seasonality of employment, a chronic weakness in the State's developing economy, tended to recline over the thirteen year period. The absolute variations in employment grew, but at a much slower rate than did total employment; hence, the relative importance of the seasonal fluctuations decreased. Expansion of oil exploration and shellfish harvest and processing brought significant contra-seasonal, economic activity. For example, oil exploration activities in marshy or ice-rich permafrost areas are generally more efficiently conducted when the ground is frozen.
>
> "Over the report period, the structure of the State's economy tended to resemble, more closely, the national economy, as most of the sectors grew closer into line with their national counterparts. The many inter-industry and intra-industry changes which contributed to this transition are . . . (partially) . . . described within the following figures and tables.

The tables and figures that follow have been taken from "Annual Population and Employment Projections 1961-1980," pub. March, 1974. State of Alaska, Department of Labor, Research and Analysis Section.

The two illustrations, State and Regional Population and State and Civilian Workforce, summarize the materials presented in the tables following them. The third illustration is a map showing the regions for which the projections are made. The Interior section is omitted because of its distance from the coast.

The vast majority of the population in the north, northwest and southwest regions live on the coast. In the southcentral region the majority of the population lives in the Cook Inlet Basin which includes the Palmer-Wasilla-Talkeetna, Anchorage, and Kenai Peninsula area. The remaining population in southcentral is estimated at less than 10,000 people that live along the coast.

Although all of southeast Alaska is included in the table, only a fraction (approximately 3-4,000) are within the area covered earlier as the central and eastern Gulf of Alaska outer continental shelf district.

Detailed studies of the population living on the coast on south-central or in the eastern Gulf of Alaska are unavailable for inclusion now.

STATE AND REGIONAL POPULATION

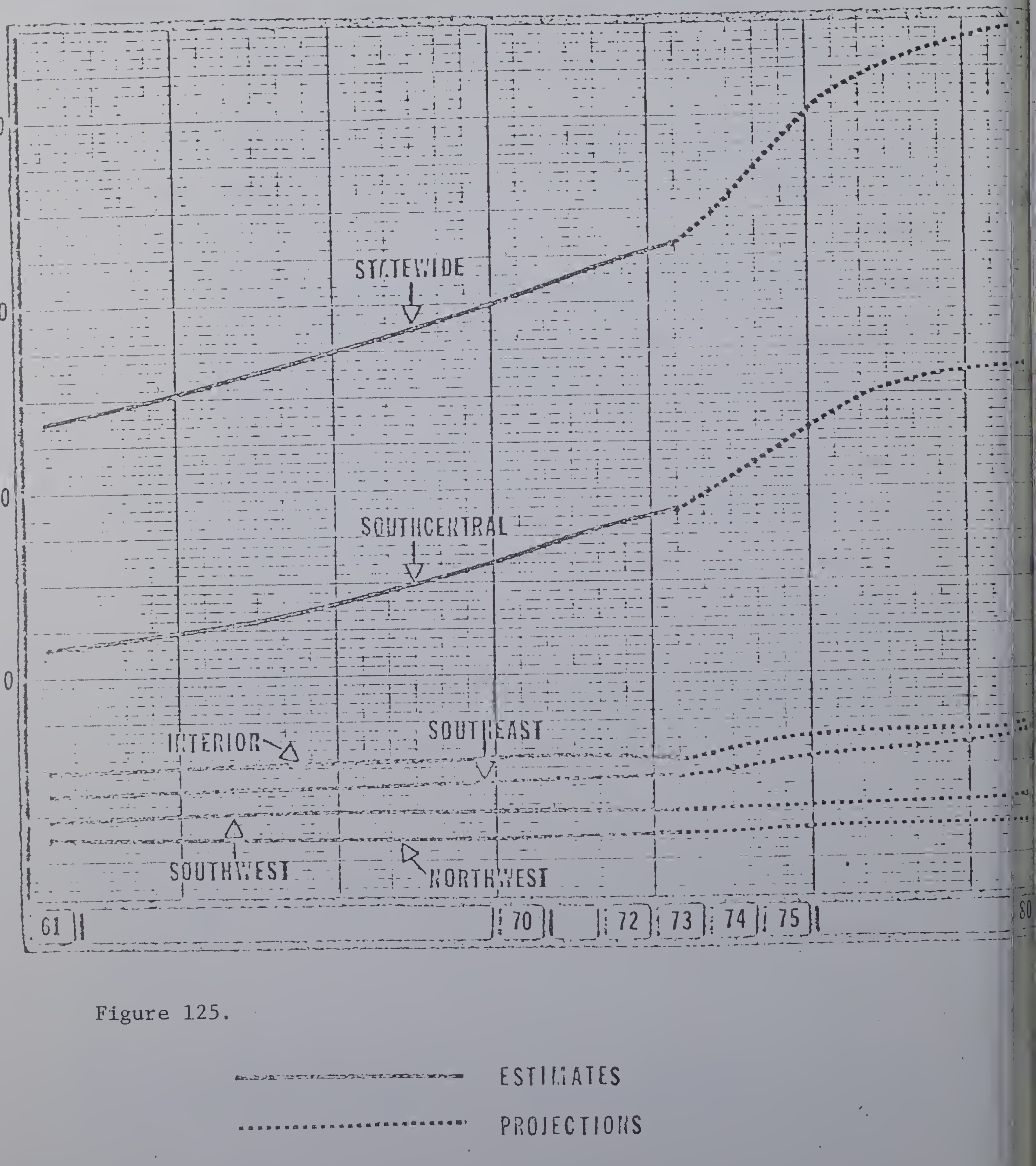

Figure 125.

STATE AND REGIONAL CIVILIAN WORK FORCE

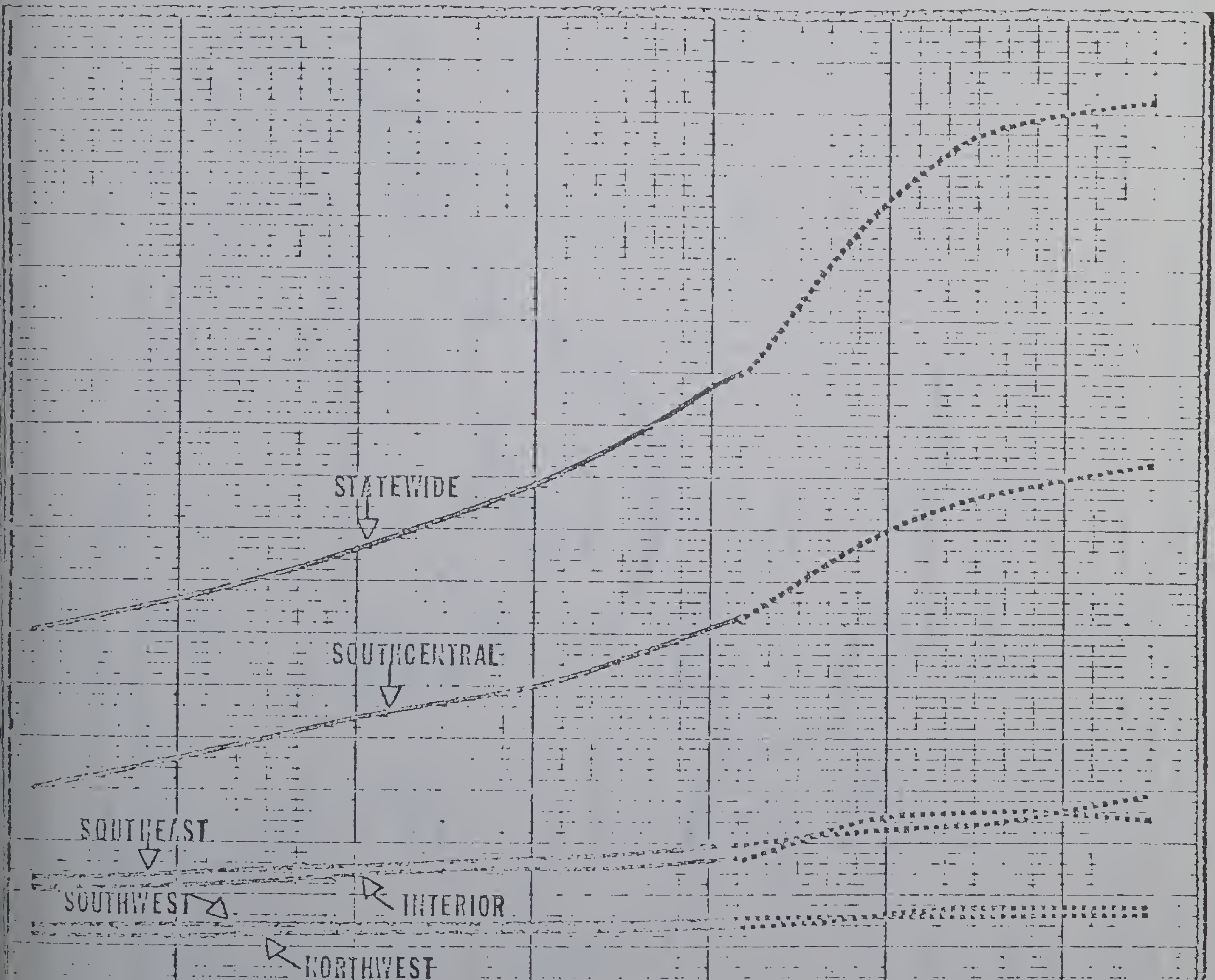

Figure 126.

——— ESTIMATES

········ PROJECTIONS

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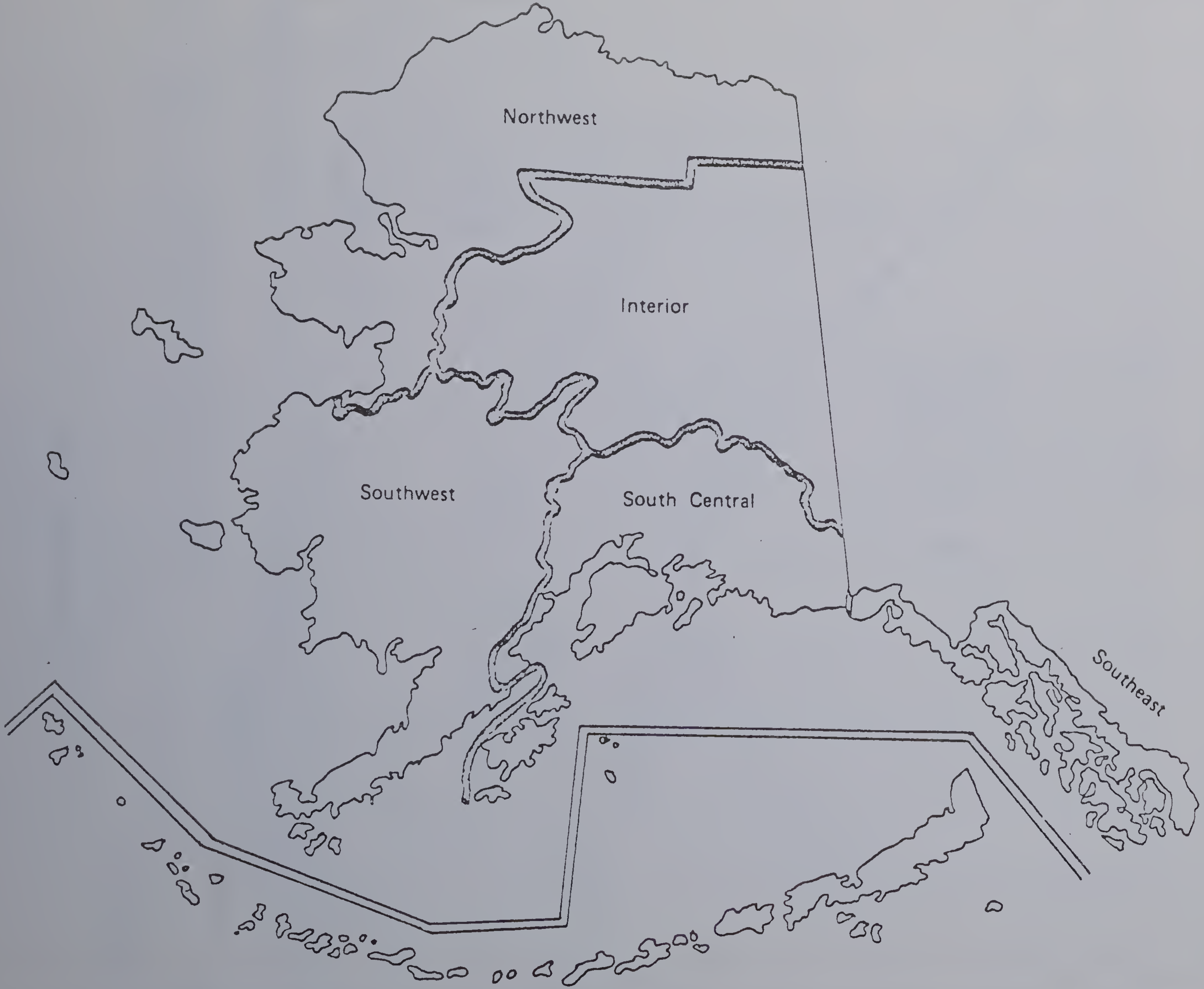
~~152~~


Northwest
Interior
Southwest
South Central
Southeast

NORTHWEST 1/

(All work force and employment data = 12 month average, in thousands of persons, for calendar year.)

	1961	1970	1972	1973	1974	1975	1980
Total Population (July 1)	12.7	13.3 2/	13.4	12.9	14.6	16.4	16.5
Total Civilian Work Force	2.8	4.5	4.7	4.8	6.8	8.4	8.8
Rate of Participation 3/	22.0%	33.8%	35.1%	37.2%	46.6%	51.2%	53.3%
Total Unemployment	0.6	0.6	0.7	0.6	0.7	0.7	0.9
Percent of Civilian W.F.	21.4%	13.3%	14.9%	12.5%	10.3%	8.3%	10.2%
Total Civilian Employment 4/	2.2	3.9	4.0	4.2	6.1	7.7	7.9
Self-Employed, Agriculture, Family Worker, Etc.	0.4	0.2	0.4	0.3	0.3	0.3	0.3
Government (Civilian)	0.6	1.1	1.6	2.1	2.3	2.4	2.9
Federal	0.5	0.6	0.7	0.7	0.7	0.7	0.7
State & Local	0.1	0.5	0.9	1.4	1.6	1.7	2.2
Mining	0.1	0.9	0.4	0.3	0.6	1.0	2.0
Contract Construction	0.1	0.5	0.3	0.2	1.4	2.3	0.6
Manufacturing	0.0	0.1	0.1	0.0	0.0	0.0	0.0
Distributive	1.0	1.1	1.2	1.3	1.5	1.7	2.1
Trans., Comm., Public Util.	0.5	0.4	0.4	0.5	0.6	0.6	0.8
Trade	0.4	0.3	0.3	0.3	0.3	0.4	0.4
Finance, Ins., Real Estate	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Services & Miscellaneous	0.1	0.4	0.5	0.5	0.6	0.7	0.8

1/ Sum of five major geographical areas may not in all cases equal statewide totals due to rounding.
2/ Final 1970 Census Estimate adjusted to July 1, 1970.
3/ Rate of participation = Total Civilian Work Force divided by Total Population.
4/ The Total Civilian Employment may not equal the sum of individual industry employment figures due to rounding.

Table 76, cont. ESTIMATED POPULATION AND EMPLOYMENT

SOUTHWEST 1/

(All work force and employment data = 12 month average, in thousands of persons, for calendar year.)

	1961	1970	1972	1973	1974	1975	1980
Total Population (July 1)	22.6	27.0 2/	26.8	26.0	26.5	27.2	30.0
Total Civilian Work Force	4.6	6.6	6.8	7.1	7.4	7.8	10.7
Rate of Participation 3/	20.4%	24.4%	25.4%	27.3%	27.9%	28.7%	35.7%
Total Unemployment	0.6	0.9	1.1	1.0	1.1	1.1	1.5
Percent of Civilian W.F.	13.0%	13.6%	16.2%	14.1%	14.9%	14.1%	14.0%
Total Civilian Employment 4/	4.0	5.7	5.7	6.1	6.3	6.7	9.2
Self-Employed, Agriculture, Family Worker, Etc.	0.8	0.4	0.5	0.6	0.6	0.6	0.7
Government (Civilian)	1.2	2.1	2.4	2.8	2.9	3.0	3.6
Federal	1.0	1.3	1.4	1.6	1.6	1.6	1.7
State & Local	0.2	0.8	1.0	1.2	1.3	1.4	1.9
Mining	0.2	0.1	0.1	0.0	0.0	0.0	0.5
Contract Construction	0.2	0.3	0.3	0.2	0.2	0.2	0.5
Manufacturing	0.8	1.4	1.2	0.9	1.0	1.1	1.4
Distributive	0.8	1.4	1.2	1.6	1.6	1.8	2.5
Trans., Comm., Public Util	0.3	0.3	0.3	0.5	0.5	0.5	0.8
Trade	0.2	0.4	0.4	0.5	0.5	0.6	0.7
Finance, Ins., Real Estate	0.1	0.1	0.0	0.1	0.1	0.1	0.1
Services & Miscellaneous	0.2	0.6	0.5	0.5	0.5	0.6	0.9

1/ [illegible]

2/ Final 1970 Census Estimate adjusted to July 1, 1970.

(All work force and employment data = 12 month average, in thousands of persons, for calendar year.)

	1961	1970	1972	1973	1974	1975	1980
Total Population (July 1)	37.4	42.9 2/	44.8	46.4	49.3	53.4	66.9
Total Civilian Work Force	15.6	20.7	24.0	24.9	26.9	28.5	37.1
Rate of Participation 3/	41.7%	48.3%	53.6%	53.7%	54.6%	53.4%	55.5%
Total Unemployment	1.7	1.6	2.1	2.2	2.6	2.9	3.3
Percent of Civilian W.F.	10.9%	7.7%	8.8%	8.8%	9.7%	10.2%	8.9%
Total Civilian Employment 4/	13.9	19.1	21.9	22.7	24.3	25.6	33.8
Self-Employed, Agriculture, Family Worker, Etc.	1.9	2.2	2.4	2.4	2.5	2.5	2.9
Government (Civilian)	4.6	6.9	7.8	7.8	8.3	8.8	11.4
Federal	2.0	2.1	1.8	1.8	1.8	1.8	1.9
State & Local	2.6	4.8	6.0	6.0	6.5	7.0	9.5
Mining	0.0	0.1	0.1	0.0	0.1	0.1	0.5
Contract Construction	0.6	0.7	1.1	1.4	1.4	1.2	1.8
Manufacturing	2.4	3.6	3.5	3.8	4.2	4.4	5.7
Distributive	4.4	5.6	6.9	7.3	7.8	8.6	11.5
Trans., Comm., Public Util.	1.6	1.7	2.0	2.0	2.1	2.2	3.0
Trade	1.4	2.1	2.4	2.7	2.8	3.1	3.8
Finance, Ins., Real Estate	0.2	0.3	0.4	0.5	0.5	0.5	0.7
Services & Miscellaneous	1.2	1.5	2.1	2.1	2.4	2.8	4.0

1/ Sum of five major geographical areas may not in all cases equal statewide totals due to rounding.
2/ Final 1970 Census Estimate adjusted to July 1, 1970.
3/ Rate of participation = Total Civilian Work Force divided by Total Population.
4/ The Total Civilian Employment may not equal the sum of individual industry employment figures due to rounding.

Table 76, cont.

ESTIMATED POPULATION AND EMPLOYMENT

SOUTH CENTRAL 1/

(All work force and employment data = 12 month average, in thousands of persons, for calendar year.)

	1961	1970	1972	1973	1974	1975	1980
Total Population (July 1)	115.9	164.9 2/	183.0	188.7	206.1	223.1	265.1
Total Civilian Work Force	38.5	63.8	74.4	79.2	88.6	96.7	115.6
Rate of Participation 3/	33.2%	38.7%	40.7%	42.0%	43.0%	43.3%	43.6%
Total Unemployment	3.1	5.2	7.6	8.1	10.9	11.9	11.9
Percent of Civilian W.F.	8.1%	8.2%	10.2%	10.2%	12.3%	12.3%	10.3%
Total Civilian Employment 4/	35.4	58.6	66.8	71.1	77.7	84.8	103.7
Self-Employed, Agriculture, Family Worker, Etc.	5.9	7.8	8.4	8.5	8.7	8.9	10.2
Government (Civilian)	13.2	18.4	20.9	21.4	22.5	23.5	28.4
Federal	9.6	10.1	10.1	10.1	10.1	10.2	10.5
State & Local	3.6	8.3	10.8	11.3	12.4	13.3	17.9
Mining	0.6	1.7	1.4	1.4	1.5	1.7	2.8
Contract Construction	2.0	4.1	5.0	5.2	6.9	8.6	7.4
Manufacturing	1.7	2.7	2.9	3.9	4.4	4.7	6.0
Distributive	12.0	23.9	28.3	30.7	33.7	37.4	48.9
Trans., Comm., Public Util.	3.1	4.6	5.3	5.5	5.7	6.1	8.4
Trade	4.7	9.9	11.2	12.0	12.9	13.8	17.0
Finance, Inc., Real Estate	0.9	2.1	2.6	2.9	3.2	3.3	4.3
Services & Miscellaneous	3.3	7.3	9.2	10.3	11.9	14.2	19.2

1/Sum of five major geographical areas may not in all cases equal statewide totals due to rounding.

d. Existing Environmental Quality Problems in Coastal Zone

(1) Water Quality

Principal sources of pollution in Alaskan coastal waters have been from domestic sewage, industrial and commercial waste, and waste or spillage from ships and small boats.

Most coastal communities in Alaska do not have sewage treatment facilities. The common method of disposal is to dump raw effluent onto beaches or into bays and harbors.

The seafood industry is one of the greatest polluters of Alaskan coastal zone waters. Of the many locations in the state that have one or more seafood processing plants, the greatest concentration of such plants is in the community of Kodiak on Kodiak Island. The 15 seafood processing plants near the city of Kodiak are presently disposing of wastes directly into the adjacent bay.

Provant et al. (1971) reported that in 1970, 14 of the seafood plants adjacent to the inner harbor area of Kodiak processed 110 million pounds of fish and shellfish and that an estimated 72 million pounds of waste was discharged into coastal waters. Over the years, this continued discharge of waste has affected the water quality and associated biological communities in the inner Kodiak harbor area. Sludge samples collected at Kodiak were extremely odoriferous. Samples taken near processors' outfalls did not contain any microscopic life forms. Provant et al. (1971) also reported that sludges containing partially decomposed processing wastes are frequently observed floating on the water and that they have a strong hydrogen sulfide odor.

Another major source of pollution to coastal waters of Alaska are commercial fishermen. Commercial fishing vessels are not equipped with sewage treatment facilities and are dumping human waste and other refuse directly into Alaskan waters.

At times as many as 100 seiners or gill netters will anchor in small coves. For example, before the start of the salmon season in the Cordova area as many as 700 fishing vessels will assemble near Egg Island to await the opening of the season. During these times routine maintenance is often performed on vessels. In most cases crank-case oil and oil filters are deposited overboard. It is also common practice on most fishing boats to deposit kitchen and human refuse overboard. The net result in the water and on surrounding beaches is quite noticeable.

There exists a mistaken idea that due to the motion of tidal currents and the mobile nature of water, the dumping of refuse in a small boat harbor is inconsequential. However, oil and other refuse discharged into harbors usually have little chance of being carried out to sea as they may accumulate in slips, wash up on the harbor shores, or be deposited on the harbor bottom. Petroleum products also have deleterious effects on paint and wooden hulls of vessels, docks, and other structures located in the harbor waters.

Offshore oil and gas production has contributed to water quality degradation in upper Cook Inlet in the past. There have been about 250 oil pollution incidents reported in Cook Inlet since 1962 and since 1965 there have been over 100 incidents attributed to offshore platform operations in upper Cook Inlet.

(2) Air Quality

Most of the air quality problems in the coastal areas of Alaska are in the Anchorage and Kodiak areas. The Anchorage area has a large number of unpaved streets with heavy traffic flow which creates a severe dust problem during the summer months (Mikkelsen 1973).

In Kodiak the solid wastes discharged from seafood processors emit gases which can be detected throughout the downtown area. The floating sludge mats and the odoriferous gases emitted are aesthetically objectionable (Provant et al. 1971).

Air contaminance resulting from petroleum operations such as burning off sump pits and flaring from producing wells is being reduced in the area. Although flaring of waste gas is being phased out under Alaska state laws, platforms have pilot flames burning in the event of a blowout. The upper Cook Inlet oil production platform flare pilots have to be quite large to prevent being put out by strong winds in that area. This is creating a discernible amount of degradation to the air quality of lower Cook Inlet.

(3) Dredging Activities

Dredging activities in Alaska are currently at a minimum and pose little threat to existing environmental quality. However, if shipping in Alaska increases, dredging may become necessary to accomodate deep-draft vessels.

III. Environmental Impacts of the Proposed Action

A. Impact on the Living Component of the Environment: An Introduction

The most severe impacts that can affect organisms and communities of marine and coastal ecosystems are those that result from spilled oil. It is important to point out that predictions of effects at the community, or even population, level can not be determined from the existing literature. Rarely has an area been well-enough characterized environmentally that the changes caused by a massive oil spill or chronic pollution can be identified. Several studies have been conducted during and after oil spills in areas that were rather well known qualitatively. These include the various studies at West Falmouth by scientists at Woods Hole and others, the oil blowout at Platform "A" in the Santa Barbara Channel, and tanker groundings at Milford Haven and Cornwall, England. Quantifiable comparisons were not possible in these areas due to a scarcity of quantification of population levels and dynamics preceding the spills.

This inability to quantify the effects of large oil spills makes the prediction of impacts resulting from the ten million acre proposal an extremely difficult task that can be done only in qualitative terms in most cases. There are currently about ten million acres under active lease in the Gulf of Mexico. No geographic area would have ten million acres offered in 1975, so effects would be generally less than those observed in the Gulf of Mexico, aside from catastrophic localized spills. The initial development would probably be the most traumatic in frontier areas, as it would necessitate intensive development of rig construction and transportation areas, an influx of new, specialized employees, construction of pipelines and onshore terminals and treating facilities, initial impacts on biota of all types of many of the noxious substances attendant to OCS oil and gas development (oil, drilling muds, formation waters), and restrictions on commercial fishing activities, among others. It is felt that many, if not all, these activities will elicit more negative responses than similar activities in currently stressed areas such as the Louisiana and Texas OCS. This will probably be true even in frontier areas that are already stressed by oil pollution, because of the variety of new loads which will be introduced into these frontier area ecosystems. Some accommodation and adaptation can be expected to occur over time. This can be inferred from the apparent health of the Gulf of Mexico ecosystem, where commercial fish catches of all types have either held steady or increased over the last 25 years, both in total catch and catch per unit effort. Unfortunately, environmental awareness was not as intensive a topic in the days when extensive offshore drilling began in Louisiana, and thus the effects of such activities were not studied in any detail at the outset. Consequently we can not predict in truly quantitative manner what the impacts of offshore drilling will be in newly opened areas. Our projections are based on more recent work, work that has been prompted by our realization of the importance of oceanic ecosystems.

Five general categories of effects of oil on organisms (and thus populations, etc) have been identified in various reports. These are:

1) lethal toxicities
2) sublethal description of physiological or behavioral activities
3) effects of direct coating by oil
4) incorporation of hydrocarbons in organisms, causing tainting and/or accumulation of hydrocarbons in food webs
5) changes in biological habitats

Other aspects of operations can also cause severe disruptions in biotic communities. Pipeline burial in submerged waters, and pipeline crossing of onland habitats is perhaps the second most severe impact producing aspect after oil spills. Pipeline burial produces effects similar to dredging activities, i.e. increased turbidity and resuspension of toxic materials normally trapped in sediments. Pipelines crossing beaches and wetlands cause short-term one time effects, but, in marshes especially, the pipe channels, access canals necessary for construction equipment, and dredge spoil banks remove habitat and cause drainage and circulation modifications. It is difficult to predict how these affect communities.

Discharges from drilling rigs represent another impact - producing aspect of operations. Drilling is accomplished with a colloidal suspension called drilling mud which cools the drill bit, carries off drill cuttings, and maintains outward pressure inside the hole. This mud is a combination of numerous specialized chemicals. These chemicals contain elements and compounds which, while usually present to some degree in seawater, represent an unknown factor that may be deleterious to marine organisms and communities. Several compounds are known to be toxic to fresh water fish in usage concentrations (e.g., ferrochrome lignosulfonate) (Falk and Lawrence, 1973). However, many toxicities are determined in laboratories, and field conditions are distinctly different.

Drill cuttings themselves are discharged overboard after being cleaned of any extrained oil. However, they do cause smothering of organisms when they cover the bottom, and the finer sediments trail away as a plume from the discharge spout, possibly causing turbidity related problems to organisms when they settle out. Formation waters (from within the geologic structures) have a high salt content and are usually devoid of oxygen. These waters are also dumpted overboard, possibly causing localized disruptions to phytoplankton and zooplankton productivity.

Another impact of note is the onshore loss of habitat from the construction of new pipeline terminals and treating facilities. In some instances, new refineries are built; these too result in loss of habitat, as well as degradation of air and water quality. It is difficult to predict whether new refineries will result from the proposed increase in acreage leased. Projections of increased production of oil do not equal the current level of imported crude, so production from this proposal could be assimulated by existing refineries. The possibility of new refineries is more a geographic - transportation problem.

B. Impact on the Offshore Environment

Impacts on open ocean ecosystems will result from accidental loss of debris, discharge of drill cuttings, sand, drilling fluids, the burial of pipelines, and the accidental spillage of oil or other toxic materials. It must be recognized at the outset that oil spills probably represent the most severe threat to biota, but various fractions of crude oil present greater or lesser threats. The natural (chemical, physical, and bacteriological) degradation of crude oil is a complex and not well understood process. Additional complexities such as local concentrations of various hydrocarbon fractions, and the different effects of these concentrations on different species are interrelated with the degradation process. Much of our knowledge of these factors has been obtained through laboratory studies, poor analogs for the natural environment. Available information will be presented in the appropriate sections following.

1. Description of Impacts

a. Pelagic Marine Life

Pelagic marine life includes a broad spectrum of organisms from all trophic levels and includes the phytoplankton, zooplankton, nekton, and demersals (shrimp, fish, squid, and marine mammals).

(1) Impact on the Plankton

Impacts that may be anticipated to have an effect on plankton will result from accidental spills of oil and other toxic materials, discharge of drilling fluids and formation waters, and burial of pipelines.

After an oil spill has occurred, that oil which has not evaporated, been carried ashore, or cleaned up will float at the surface for a time and eventually be dispersed as minute droplets in the water. In addition, certain components of crude oil are slightly soluble in seawater. In each of these three phases (floating, droplets, solute) the oil has the opportunity to damage marine organisms and/or enter the marine food web. The organisms most immediately and drastically affected are those which are found in close proximity to the sea surface.

Spooner (1969) noted that plankton collections taken after the Torrey Canyon oil spill showed damage to minute plant cells of the order Prasinophyceae which float at the surface. A high proportion (50-90%) of pilchard (fish) eggs, which also float, were dead and there was a local shortage of pilchard larvae. Spooner was unsure whether this damage was done by oil alone or by oil and the emulsifiers which had been used to disperse the oil.

Hufford (1971) noted laboratory studies which indicate that oil can affect phytoplankton after several days exposure. He cited laboratory experiments in which oil products in seawater inhibit cellular division and cause death in phytoplankton. Apparently, cellular membranes were damaged by the penetration of hydrocarbons

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and this led to the extrusion of the cellular contents. According to Mironov (1971), laboratory studies indicated that cell division in phytoplankton was delayed or inhibited by crude oil concentrations ranging from 0.001 to 1000 ppm.

During a study of the effects of the Santa Barbara spill, however, Oguri and Kanter (1971) found no conclusive evidence of a decrease in phytoplankton community productivity that could be attributed directly to the oil spill. Individual experiments indicated, however, that the use of dispersants may have resulted in marked reductions in productivity. Oguri and Kanter theorized that the longevity of any such effect would depend on the currents and rate of dilution, as well as the type and quality of the dispersant. Gordon and Prouse (1973) found that at petroleum hydrocarbon concentrations below 10 to 30 ppb, photosynthesis was enhanced, but crude and refined oils in concentrations from 60 to 200 ppb suppressed photosynthesis to varying degrees. Number 2 fuel oil has the greatest effect, suppressing photosynthesis by 60% in concentrations between 100 and 200 ppb.

No evidence was found in the literature that spilled oil enters marine food chains via adsorption or absorption by phytoplankton and subsequent ingestion by grazing herbivores.

The floating seaweed Sargassum and its associated community would be damaged by floating oil. In mature states, this seaweed, along with broken blades of seagrasses, can form large floating mats, patches, or long windrows. This is a very rich community including a large *aufwuchs* (living attached to, or gliding upon) component, and a rich plankton component. In addition, many juveniles of fish, squid, and other nektonic forms are associated with the floating masses (LaRoe, 1972). It is conceivable that oiling of the *Sargassum* would cause it to adhere and form tight mats or clumps, resulting in complete destruction of the community.

Little information has been found concerning the effect of crude oil on the zooplankton. Hufford (1971) cited one experiment which showed accelerated death of zooplankton exposed to diesel oil (0.1% for 5 to 60 minutes) as compared to non-exposed zooplankton. Mironov (1971) stated that some copepods are sensitive to a 1 ppm suspension of fresh or weathered crude oil and diesel fuel. Zooplankton have been observed to ingest spilled Bunker C oil particles, however, with no apparent effect. Members of the Operation Oil Task Force (1970), studying the effects of spilled Bunker C from the tanker *Arrow* in Chedubucto Bay, Nova Scotia, observed that many copepods in the area had apparently ingested small oil particles and 2.4% Bunker C was found in the feces of one species. They noted that animals containing smaller oil particles voided these within 24 hours and showed no signs of distress. That they continue normal activities with no apparent harm is quite important to higher trophic levels in the marine food web, because they can be eaten by small fishes and filter-feeding organisms while carrying the oil in their guts. The fish and filter-feeders may in turn be eaten by larger predatory animals, establishing the potential for a classic example of biological magnification of a potentially harmful or toxic compound. This concept of biological magnification is generally described as the selective absorption of a substance by a particular type of organ or tissue component (e.g. lipids). If this organ or tissue component is digested and further selective absorption occurs, higher concentrations of the substance can be generated than are found in ambient conditions. This effect is most critical when the substance is toxic (acute or sublethal) or creates non-marketable resources. A similar effect could be expected if other toxic materials such as diesel fuel, solvents, or heat exchanger fluids were spilled during handling or as a result of platform damage.

The preceding discussion includes only the results of massive, infrequent spills. However, statistical evidence exists that small spills of fractions of a barrel to 50 barrels occur on the order of a thousand times per year in the Gulf of Mexico where the most extensive OCS oil and gas development is found. The problem of determining potential impact from chronic, low-level spillage is difficult. Virtually none of the reports of scientific investigations on oil spillage addressed the effects of low-level, continuous spillage in offshore water. It is difficult to assess or predict potential damage to one group of organisms, i.e., plankton, but it seems appropriate to discuss the problem at this point. A few scientists have offered cautious speculation. Blumer (1969) stated: ". . .we are rather ignorant about long-term and low-level effects of crude oil pollution. I fear that these may well be far more serious and long-lasting than the more obvious short-term effect." Blumer (ibid) then pointed out that hydrocarbons are taken up into the food chain, and through the process of biological magnification can become concentrated in marine species used by man for food. He stated, "One consequence will be the incorporation into food of materials which produce an undesirable flavor. A far more serious effect is the potential accumulation in human food of long-term poisons derived from crude oil, for instance of carcinogenic compounds." Blumer also cautioned that low-level pollution may damage the marine environment by masking natural chemical sex attractants, interfering with chemical food sensing and enemy repulsion. He stated, "There is good reason to believe that pollution interferes with these processes in two ways: by blocking the taste receptors and by mimicking for natural stimuli; . . . ."

In offshore areas, where chronic spills could result from leaking vessels and plumbing, and discharge of oil-contaminated, produced brine waters, St. Amant (1972) viewed the problem somewhat differently:

> "Chronic pollution from offshore production sites represents an unknown factor. Daily drips and loss of small amounts of oil or other chemicals overboard do not appear to generate ecological problems because of the relative immensity of the water column. Whether such sublethal pollution will eventually accumulate and cause environmental degradation is yet to be determined. Because of this unknown factor, significant effort should be made to prevent low-level pollution."

Oppenheimer 1/ noted that hydrocarbons have been a part of the natural environment since life began. He further stated that, ". . .except for the commercial concentrations of oil in our atmosphere, no recognizable concentration of specific molecules have persisted in the aquatic environment other than tar balls, as microorganisms are urbiquitous in their role in mineralizations or recycling of the hydrocarbons in natural environments."

Oppenheimer continued:

> "There is a priori evidence that hydrocarbons may in some areas be significant as a nutrient source of living organisms. It may not be surprising when one looks at the pathway of hydrocarbon degradation. A first step of degradation is the formation of fatty acids which is a good source of food for marine organisms. It is interesting to note that the fish catch in the oil producing areas of Louisiana has increased materially during the past 30 years. Fishing effort in the Gulf remained somewhat constant over the last 10 years with 10,000 small boats and 3,500 vessels operating... Logic tells us that fish must be present if they are being caught. This fish catch increase is in an area where nearly 3 billion barrels of oil have been produced over the last 30 years. I find that total fish catch, as it represents the top of the food chain, can be a good indicator for the state of the environment."

1/ Oral and written testimony given by Dr. Carl Oppenheimer of Univ. Texas Marine Station at the OCS Public Hearing on a proposed oil and gas lease sale offshore Louisiana. August 23, 1972. New Orleans, Louisiana.

In his summary, Oppenheimer noted, ". . .there (is) no conclusive evidence of long-term adverse oil effect on the living populations. . ."

It is our conclusion, based on past performance that sooner or later a major spill will occur wherever there is significant development of offshore exploration and production in potential areas. We are certain that thousands of minor spills will occur. As to the effects of a major spill on plankton, and the entire ecosystem as well, we endorse the conclusions of Dr. James I. Jones, Research Coordinator of the Coastal Coordinating Council, Florida Department of Natural Resources. 1/ He stated that:

> "The catastrophic major oil spill is the single most visible, and therefore to a degree, most controversial of any aspect of petroleum production and transfer. While there is no question that a major spill does indeed cause a massive destruction to both flora and fauna, as well as the environment itself, these effects are of a temporary nature in most respects. The natural recovery capability of a healthy ecosystem is such that the massive mortality and destruction attendant with a major spill will allow a recovery of the ecosystem, with some alteration, within a relatively few years. In those areas where the ecosystem is already stressed, however, as is the case in many areas within the coastal zone, a single catastrophic spill could well create effects that are far beyond the natural recuperative powers of the ecosystem."

We believe that the plankton populations in the various geographic areas will be able to absorb the impact of a major oil spill and recover fairly rapidly. This is based partly on the lack of

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1/ Letter, through State of Florida, Department of Natural Resources, dated June 22, 1973.

evidence (although attempts have been made) that plankton populations are catastrophically impaired by oil spills, and that the suggestion is valid of Straughan and Abbott (1971) that the rapidity of multiplication of planktonic organisms overcomes the effect of any local or temporary reduction of population sizes. Our greatest concern is for coastal areas and estuaries, which are discussed later. It is not likely that significant amounts of oil spilled from platforms would reach most coastal areas, because of the distance from shore, prevailing winds and currents, and clean-up operations, but this would be examined more closely in a site-specific impact statement where tracts are identified.

The regular discharge of formation waters, "oil field brines", could have a severe local impact on the plankton. It has been conjectured that the brines also could serve as a "fertilizer" in shallow seas which might trigger a red tide.

Although formation water is put through a polishing facility and has all but traces of entrained oil removed (not greater than 50 ppt, average) it may contain a heavy concentration of dissolved salts 1/ and is anoxic (devoid of dissolved oxygen). It could be anticipated

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1/ An average of 141,473 mg/l was found in the examination of over 80 examples of formation water taken from South Louisiana and the OCS. This value may be compared to the world average of 35,000 mg/l for natural seawater.

that the release of this water would result in a plume trailing away from the point of discharge in the direction of the current with a core perhaps a few feet in diameter and tens of feet in length. This plume would probably be harmful or lethal to the plankton. Physiological stress would probably result from an osmotic imbalance (cells losing water to surrounding brine) and low or dissolved oxygen. Beyond the zone of stress, however, Mackin (1971) noted a zone of stimulation or fertilization during a study of brine discharge in Galveston Bay.

Red tide outbreaks have occurred in several coastal areas of the Gulf, notably the west coast of Florida and east Texas and in different locations on the Atlantic seaboard. Ingle and Martin (1971) have correlated red tide occurrences in Florida with iron compounds of various types and concentrations. Formation waters contain iron in the range of 15 to 153 mg/l, but the amount of iron postulated by Ingle and Martin as necessary to trigger a red tide could not be supplied by oil field brines. We do not believe that iron or other constituents of brines could cause red tides, either because the concentrations are too low or because they are not now known to be limiting factors in red tide blooms.

The remaining impacts suffered by the plankton will be localized, and are all related to increased turbidity. These impacts are brought on by the discharge of drilling fluids and drill cuttings, and the jetting of sediments during underwater pipeline burial. The turbidity conditions resulting from these operations are seen as a visible plume in the direction of local currents and usually disappears within a few yards to a mile from the source. The effect of this turbidity on a given parcel of water is of short duration, lasting on the order of a few hours at the most. The physiological effect on phytoplankton is to depress photosynthesis by obstructing the penetration of sunlight. It is our conclusion that the effect of increased turbidity would be immeasurably small at more than a few feet from the point of discharge.

Of particular interest are the planktonic larvae of various benthic invertebrates. These meroplankters (planktonic for part of life cycle) are generally considered to be most sensitive to environmental stress and predation while in the water column, although Mironov (1970) concluded that they were not as sensitive as holoplankters. Pelagic larvae are the primary means by which benthic invertebrates distribute themselves over wide geographic areas. Based on the high reproductive potential and numbers of larvae released by these animals, we feel that, while there may be a locally adverse effect, distributional and survival powers will not be significantly affected.

(2) Impact on the Nekton

The term nekton, by definition, includes all marine animals which are active swimmers and are able to migrate freely over considerable distances. This motility, combined with irritation sensing ability and natural escape and avoidance behavior, enable them to avoid localized adverse conditions.

Therefore, the only significant impact on the nekton would be as a result of a massive oil spill which they can not quicly avoid.

No information has been found on the effect of spilled oil on members of the nketon other than fish. Hufford (1971) cited several early studies which show that crude and bunker oils harmed or killed fish eggs in laboratory experiments. He also cites Mironov (1970) who found that oil affects fish respiration by clogging gills and damaging gill tissue. At the behavioral level, Nelson-Smith (1971) has stated that fish seem to avoid contaminated areas. While this has survival value for the fish, the contaminated areas then constitute unusable habitat. A more common (and easier) approach to studying the effects of oil on fish is to expose them to various amounts of oil in a laboratory aquarium (e.g., Spears, 1970) but this is not of great value in assessing the impact of spilled oil in the ocean because of the vast different between an aquarium and the ocean and the fact that oil concentrations in the water during a spill are rarely known. Rice (1973) has noted that in laboratory studies, pink salmon fry are able to detect low, sublethal concentrations (as low as 1.6 mg/l of oil for older fry) of Prudhoe Bay crude and show avoidance behavior to it. He acknowledged that the effects of sublethal concentrations of oil on salmon migrations are unknown, but emphasized that the potential for harm is clear. This potential is clear on the West Coast and can probably be generalized for other migratory fishes. The acute toxicity of petrochemical drilling fluids components and wastes to some fresh water fish was investigated by Falk and Lawrence (1973). A standard 96 hour, LC 50 test was used and 13 components were found to be toxic or moderately toxic to chubs and rainbow trout.

Blumer (1969) proposed that physiological/behavioral effects may interfere with fish nutrition by:

a) blocking taste receptors, and

b) mimicking natural chemical messengers which attract predators to their prey.

Boesch (1973) cited the unpublished work of Todd and Atena (Woods Hole Oceanographic Institution, Chemotaxis Group), who worked with behavior patterns of yellow bullheads, Ictalurus natalis. They found that the fishes complex, chemically-mediated social behavior developed high intensity conflict behavior when exposed to water soluble fractions of Kuwait crude oil.

It is also significant that fish could suffer stress from feeding on contaminated prey such as the oil-ingesting copepods mentioned earlier.

No information has been found on spilled oil affecting numbers of the nekton other than finfish. Brownell (1971) and LeBoef (1971) investigated the effect on marine mammals of the Santa Barbara oil spill. Numerous dead animals found after the spill, including gray, sperm, and pilot whales, dolphins, and elephant seal pups, were examined histologically and chemically for the presence of oil or pathological effects related to oil. No such oil or pathology was found and the deaths were attributed to natural causes. It was also noted that the number of deaths was not abnormally high.

On the basis of the Santa Barbara spill data alone, it is difficult to predict effects of an oil spill on marine mammals; however, we presume it will be negligible as long as the mammals are able to escape the area of the spill.

In summary, we are unable to predict the total scope of the impact on nekton in quantitative terms. Based on past observations, we estimate that the overall impact will be minimal.

2. Benthic Marine Life

Environmental impacts which may be expected to affect benthic life adversely will result from the discharge of drill cuttings, accidental spillage of oil (and any associated use of emulsifiers) and other toxic materials, and the burial of pipelines.

Spilled oil which has not evaporated or been cleaned up or stranded on a beach, after being dispersed into the water as droplets, adheres to particulate matter and sinks to the bottom where it comes into direct contact with the benthos.

Data of Sanders, Grassle, and Hampson (1972) show immediate and nearly complete mortality of many forms of benthic animals following the spill of No. 2 fuel oil near West Falmouth, Massachusetts. The bivalve molluscs (clams, etc.) seemed especially vulnerable. As a rule, when levels of oil concentration in the sediment apparently decrease below a certain level with the passing of time, affected areas were recolonized by resistant forms, especially the marine polychaete worm _Capitella capitata_. This generally occurred within three to six months of the initial oiling. With the passage of about 10 to 20 months, the more sensitive molluscs resettled many areas. However, at some harbor stations which apparently received a heavy oiling, some highly sensitive forms such as the ampeliscid amphipods [1] had not returned. Farther offshore, this return required about six months.

During drilling operations, drill cuttings are separated from the drilling fluid, cleaned of any entrained oil, and discharged into the ocean. A diver survey during one operation offshore Louisiana revealed that the drill cuttings could be detected over a circle

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[1] A family of crustaceans related to the common beach hopper or beach flea.

100 feet in diameter. In a small area in the center, the deposit appeared to be about four feet thick. The same survey of the cuttings deposit showed that benthic animals either migrated up through the deposit as it accumulated or colonized even as deposition continued, because it appeared to be inhabited by several animals characteristic of "normal" benthic fauna.

The number of wells that contributed to the pile of cuttings noted in this diver survey was not indicated. A typical 10,000 foot well may generate 700 tons of cuttings, and up to 20-30 wells may be drilled from a single platform. It is our opinion that the 100 foot diameter pile of cuttings may represent cuttings from one or several wells. The total amount of cuttings from 20 to 30 wells would probably cover a larger area around the base of a platform. The distribution of these cuttings would depend on currents and on size of the cuttings.

If drilling operations were carried out over the relatively harder carbonate sand bottoms, it is possible that the highly productive seagrass beds might be smothered by the drill cuttings which are discharged overboard. Unfortunately, the offshore distribution of grasses is apparently patchy and not well known. Therefore, it cannot be said with certainty that such an impact would occur.

Also associated with these relatively hard bottoms are small to large populations of non-burrowing, attached benthic animals such as the sponges, soft corals, anemones, bryozoans, and others. The extent and duration of the impact are impossible to predict at this time. If the drill cuttings are similar in consistency and composition, colonization and repopulation could proceed rapidly. If, on the other hand, the drill cuttings were wholly foreign in consistency and composition, the deposit might remain barren for a long period or be populated by different types and numbers of animals.

The effect of drill cuttings may be further complicated by the periodic discharge of non-oil based drilling muds. In the past these have been assumed to be harmless. However, drilling muds often contain large amounts of barium compounds. The barium in drilling muds represents a serious, but as yet undetermined, threat to aquatic life, because it is known from upland operations that barium compounds have a severe, almost sterilizing effect on plant and animal life of the soil (EPA, undated).

Investigating on behalf of the Gulf Universities Research Consortium Offshore Ecology Investigations (1974), Dr. James I. Jones has found barium compounds to be above "normal" background levels in sediments of Grand Isle, Louisiana, where drilling has gone on for many years. Nevertheless, they are low enough to present no known biological hazards. Considered separately from drilling muds, we do not expect the regular discharge of drill cuttings to result in a reduction of the benthic communities of the continental shelf.

In water depths of less than 200 feet new pipelines are entrenched by jetting away the sediment beneath the pipe and allowing the pipe to settle into the underlying trench. Subsequent burial is allowed to take place naturally, primarily by reworking of sediments by bottom currents. The jetting process physically disrupts the sediments in its path and also causes resuspension of large quantities of sediment.

Most, if not all, benthic fauna are either destroyed by the jetting or raised into the surrounding water and rendered completely vulnerable to predation. Although recolonization would begin immediately, the native fauna could not be fully restored until seasonal reproduction cycles had been completed by representative species from adjacent areas, which would provide a supply of larvae to settle and enter the reworked substrate.

Turbidity resulting from resuspended sediment is capable of producing an adverse impact on filter-feeding molluscan and crustacean benthos by clogging the filter-feeding apparatus or blocking respiratory surfaces. Casual observation has revealed that ocean currents carry the sediment and redeposit it at various distances, depending upon the particle size of the sediment.

Another possible source of impact during pipeline dredging is the resuspension of toxic heavy metals and persistent pesticides that may have been deposited in the area by a polluted stream and land runoff. The possibility exists that these toxic materials could be ingested by lower marine life and could then be magnified through the food chain until they accumulated in serious quantities in top carnivores, including species harvested for human food.

Obviously, we must conclude that the benthic community will be disrupted or destroyed in the path of pipeline dredging operations. We believe the duration of the impact will be short, with recolonization being completed within a year or two. The possibility of impact by resuspended toxic heavy metals and persistent pesticides exists, but the predictions for the occurrence, location, scope and duration of the impact are unknown.

c. Oceanic Birds

In the past, the injuries and deaths of thousands of seabirds, shorebirds and waterfowl have been the most obvious impacts of massive oil spills. According to R. B. Clark (1973), the only organisms damaged directly by oil pollution on a sufficient scale to affect the world, or even local populations, are seabirds. Nelson-Smith (1973) stated that a very large number of oceanic and shorebirds die as a result of oil pollution, and that chronic pollution probably kills more every year than die after a single catastrophic oil spill. Tanis and Moerzer Bruijns (1968, in Nelson-Smith, 1973) estimated that total annual losses due to oil pollution in the North Sea and North Atlantic, excluding specific disasters, range from 150,000 to 450,000 seabirds.

The causes of mortality and damage to bird fauna from hydrocarbon contamination are usually complex and may result from several interacting factors. Shelton (1971) states that:

> "Clogging of plummage greatly reduces (a bird's) insulating properties, while ingestion of oil during preening can cause a variety of pathological conditions including severe enteritis and necrosis of the duodenum... This, in combination with increased heat losses, may reduce feeding activity and a marked drop then occurs in the fat reserves of the bird. It is in this critical conditions that most oiled birds arrive on the shore where further stresses are put on them by cleaning and attempts at rehabilitation. It is therefore not surprising that the mortality rate of cleaning centers is very high indeed."

Internal contamination of birdlife may follow preening of feathers. Internal toxicity of polluting oils is a definite factor in the observed mortalities due to exposure to petroleum hydrocarbons as was demonstrated by Hartung and Hunt (1966). These experiments determined the lethal dose of oil to certain ducks ranges from 1 to 4 ml per kilogram (mg/kg) when the birds were kept outdoors under environmental stress. A duck was expected to clean 50% of the polluting oil from its feathers during the first few days after contamination. Hartung and Hunt concluded that if a duck acquired 7 grams of oil on its feathers, it could ingest oil to meet the experimentally established lethal dose of 1 to 4 ml/kg.

The effects of long term chronic pollution on birds in Great Britain have been studied by R. B. Clark (1973). Auks, arctic species which migrate to Great Britain, have a low rate of replacement and are thus more susceptible in the long-term to high early mortality from natural causes than those which are more prolific. Clark states that "Diving sea ducks have a greater reproductive potential and do not appear to have declined despite repeated heavy losses from oil pollution."

Several European populations of seabirds have declined significantly and this is attributed to both major and minor spills from shipping accidents, tanker discharges, oily wastes from shore discharges (R. B. Clark, 1973). However, downward trends in European bird populations may also be the unfortunate result of industrial pollution other than from petroleum. The use of pipeline transport systems in Louisiana will prevent spillage from the above sources, although potential pipeline leakage must be considered as a possible source of oil.

In the Gulf of Mexico, bird mortalities due to oil pollution are less frequent due to the fewer number of spills which have occurred there. However, damage to birdlife has been documented for the oil spill in Tampa Bay, Florida. On February 14, 1970, the tanker Delian Appolon ran aground, spilling a cargo of Bunker C oil into Tampa Bay. It was not possible to assess with accuracy the total number of birds harmed or killed because of the northward migration of waterfowl then occurring. Presumably, some of the oiled birds left the immediate area during their migratory flight. It is known that approximately 3,500 oiled birds were captured and treated although an accurate measure of success is not given (Florida Game and Freshwater Fish Commission, unpublished Report). R. B. Clark (1973) estimates that, as a rule, only 10-25% oiled birds which die offshore wash up onto the beach. He does not estimate the number which make it to shore after contamination.

During March, 1970, an oil spill occurred at the Chevron platform "C" located 10 miles east of the 48,000 acre Delta National Wildlife Refuge and 9 miles southeast of the 7,500 acre Breton Islands. The Department of the Interior (1970) reported little unfavorable impact to birdlife as a result of this spill because it occurred at a time when many species were temporarily in their northern breeding grounds. In addition, the Mississippi River riptide served as an effective barrier to the shoreward movement of oil when onshore winds did occur. According to the report, however, had the spill occurred earlier in the year or during the winter, large numbers of migratory waterfowl could have been destroyed.

d. Unique Environments

Unique environments are those areas with distinctive biological characteristics that set the area apart from surrounding areas. While this designation may be strictly interpreted to include all habitats, it is intended that the phrase denote areas that would appear significantly different to a non-naturalist. These areas include the marshlands and barrier islands on the Atlantic and Gulf coasts, wildlife refuges and sanctuaries on all coasts, coral reefs and isolated reef-type communities in the Gulf of Mexico, shell reefs on the Atlantic and Gulf coasts, highly productive estuaries, the kelp beds of California, bird and seal rookeries on the west coast and in Alaska, and the numerous topographic highs that serve as commercial fishing banks on the Louisiana-Texas OCS. Unique environments in the four geographic areas of the OCS are more fully discussed in the appropriate section in II. DESCRIPTION OF THE ENVIRONMENT.

The impacts to these unique environments will differ in kind and intensit from the impacts on other more "normal" environments. The important consideration is that these sites are more highly valued by *people*, although in some cases these environments are important for strictly ecological reasons (e.g. highly productive estuaries, and how they contribute to ecosystem vitality). Oyster and fishing banks are valued for commercial reasons, rookeries and the other sites for conservationist/esthetic/scientific study reasons. The higher value attached to these unique environments necessitates that even more precautionary measures are taken to protect these resources from the hazards of OCS oil and gas operations.

The principal mechanism for protecting these unique resources is the special stipulation. Special stipulations can be attached to any lease sale to mitigate the potential for damage to a particularly unique feature. It is not an objective of this statement to identify all unique environments and promulgate special stipulations to protect them. This will be a primary objective of the site-specific impact statements that will be prepared within give geographic regions that become scheduled for lease sales. It is the responsibility of BLM, the public, and reviewing agencies to identify these areas to the maximum extent in order that due consideration and maximum feasible protection be given them.

2. Summary of Aggregate and Cumulative Impacts of Expanded Program and Comparison with Impacts Under Current Leasing Program

a. Pelagic Marine Life

Our present state of knowledge does not allow us to quantify the impacts of expanded leasing on phytoplankton and zooplankton populations. Oil spills would reduce primary productivity through direct killing of phytoplankton and blocking sunlight penetration into the water column. Zooplankton populations would be depressed in proportion to the non-availability of food sources. The expectation is that depression of photosynthesis activity and primary and secondary productivity would occur on a scale proportional to the degree of offshore development. However, as Straughan and Abbott (1970) pointed out, these plankton populations are capable of rapid recovery, and the impacts of catastrophic spills on plankton are probably short-term. Of more importance is the effect on these populations of chronic low-level pollution by different substances, including oil. This problem remains an unanswered question, but the possibility of reduced oceanic productivity is justification enough for utilization of best available technology to prevent low-level pollution.

Plankton populations and productivity in the Gulf of Mexico have not shown any dramatic shifts in the last 25 years, aside from seasonal variability, although the data are sketchy. It is our tentative conclusion that the plankton do not suffer measurably from OCS operations, even in highly exploited areas such as the Louisiana OCS.

The nektonic component of the pelagic fauna is generally recognized for its ability to avoid areas of obvious pollutant contamination. However, commercial resources could be affected by restricted access to fishing vessels caused by massive oil spills, as happened during the Santa Barbara spill when vessels were stuck in port. Nekton could be affected by ingestion of tainted food and by uptake of dissolved toxics. The magnitude of impacts are impossible to predict; however, the experience in the Gulf of Mexico with commercial finfish and shellfish catches indicates no diminution in total catch or catch per effort.

b. Benthic Marine Life

Most benthic marine life does not sustain direct impacts from oil spills because of water depth; it is only the shallow littoral and intertidal areas where benthic biota sustain adverse impacts. Benthic marine life in all areas will be adversely affected by platform installation, pipeline laying, and discharge of drill cuttings. These impacts will be roughly proportional to the intensity of development. Benthic fauna that utilize plankton and detritus as food sources may become contaminated if the food sources are contaminated. Again, the extent and significance of these impacts are impossible to predict, but benthic life in the Gulf of Mexico is apparently not suffering large-scale adverse effects from present offshore development.

c. Oceanic Birds

Numerous birds, both oceanic and nearshore waterfowl, have suffered mortalities as a result of massive oil spills. There is generally no measure that can mitigate these bird kills except fast-response, effective spill cleanup. Various techniques for salvaging oiled birds have met with limited success. If birds were the sole concern during oil spills, dispersants and sinking agents would also mitigate the impact on birds, but dispersants affect oceanic biota in being more toxic than the spilled oil. While it is impossible to relate bird deaths to oil spills except on an incidental basis, it is certain that oil will be spilled wherever there are operations, birds will die as a result, and the number of birds lost will increase in number as oil and gas development becomes more intensive as a result of this proposal.

d. Unique Environments

As was mentioned in the description of impacts, unique environments would suffer no greater or lesser impacts than other areas, but the value that people place on these environments warrants additional measures to ensure protection. This is done by identifying the unique environment and developing a special stipulation that adopts a reasonable technique for protecting the area (e.g., withdrawal of tracts, prohibiting cutting disposal). By the fact that frontier areas will have to be opened to implement this proposed plan, new unique environments will be subjected to the risk of massive oil spills and pipeline construction. Again, safer and more stringent operating procedures and rapid deployment of effective spill cleanup equipment can mitigate the possible deleterious impacts on these highly valued resources.

C. Impact on Nearshore and Coastal Zone Environments

Adverse environmental impacts on nearshore and onshore areas resulting from offshore oil and gas production include the following: pollution by crude oil (and toxic subfractions) and subsequent hydrocarbon uptake by organisms, pollution by other noxious substances attendant to oil and gas operations, such as drilling fluids, drilling muds, and formation waters, environmental disturbance of habitats during pipeline construction operations, and loss of habitat when land is utilized for onshore pipeline terminals and treating facilities.

Depending upon the quantity and frequency of crude oil being dispersed into the ecosystem and the time of exposure of organisms to these hydrocarbons, the introduction of petroleum into the ecosystem may create disturbances hazardous to various habitats. Existing information on the actual effects of hydrocarbons on different onshore and nearshore habitats and organisms is far from conclusive. However, accounts of biologic disruptions, or the lack thereof, following accidental spills from tankers and their operations (an activity unrelated to offshore production), from several controlled experiments, and faunal surveys in areas of oil production, do provide some basis for understanding the role of crude petroleum in the ecosystem. Future studies in waters considered for possible leasing will considerably broaden the basis. Whenever possible, the following sections discuss possible impacts on biota with respect to such factors as quantity, frequency of occurrence, and duration of hydrocarbons in the marshes, bays, sounds, beaches, and artificial and hard substrates of all coastlines. Pertinent information will be included, when available, concerning such categories of potential impacts as organisms response to oil, direct toxicities, both lethal and sublethal, incorporation or uptake of hydrocarbons by organisms, oil coating, and the unique habitats and characteristics of different geographic areas.

1. Description of Impacts

a. On Biological Communities of the Coastal Zone

(1) Beaches and Associated Biota

Sandy beaches are the most extensive shoreline habitat of the coterminous United States. Their resource value derives more from the recreational value attached to their existence than to the biota and community productivity associated with them. As such, they are more appropriately addressed in the Impact on Resources section later in the text. Effects on biota are addressed here.

True beach fauna (psammofauna) are a notably austere and inconspicuous group of organisms, comprised mainly of burrowing forms and epifaunal forms such as beach hoppers. They are relatively unimportant as major contributors to secondary productivity levels of food webs. What are of the most importance from a community and productivity standpoint are the intertidal organisms, which are more diverse, usually larger, and usually have more numerous connections with other parts of food webs.

Beach fauna suffer a severe impact from offshore oil spills as is evidenced by the results from several accidents. Crude oil from the Santa Barbara and Torrey Canyon spills reached the beaches, causing mortalities of intertidal and beach fauna. Many of the mortalities in the Santa Barbara incident were due to smothering of intertidal animals by coating with crude oil. Mitchell, et. al. (1970) noted that populations of mussels, barnacles, and periwinkles survived the initial exposure in the absence of "tar" coating. According to Ketchum (1973), "At locations where the oil film (of Santa Barbara) was not so obvious intertidal organisms were not severely damaged."

Detergents used to disperse oil in the Torrey Canyon spill complicated an assessment of damage caused by the oil. However, indications were that mortalities were light on beaches where detergents were not employed (North, 1973).

The spill of No. 2 fuel oil in West Falmouth, Massachusetts, from the tanker Florida resulted in a high number of mortalities among intertidal and beach fauna. This spill eventually covered nearly three miles of coastline and resulted in high mortalities (Blumer, et al., 1971). Results from studies of this spill demonstrated that immediate catastrophic and later chronic effects can result from a single oil spill (Sanders, 1973). In this paper Sanders concluded that species density patterns for polychaetes, gastropods, bivalves, and ampeliscid amphipods which are residents of the subtidal benthos, exhibit stress patterns dependent on distance from the spill and time of exposure of organisms to the fuel oil.

Most pollution studies for the littoral zone are concerned with rocky shoreline of New England and California and their characteristic assemblages of seaweeds, barnacles, limpets, anemones, etc., rather than for the less extensively studied sandy beach communities. To generalize, where organisms have been covered by crude oil and Bunker C fuel oil, death is primarily blamed on smothering due to physical coating (e.g. Chan, 1972; Nicholson and Cimberg, 1971). When the pollutant has been a lighter refined fuel oil, mortalities and stress have been primarily associated with toxic effects of the oil (e.g. North, Neushul and Clendenning, 1964).

Large algae are important intertidal primary producers on rocky shores, and, although they are generally resistant to oil, they may sometimes be coated and torn from the substrate (Nelson-Smith, 1974). Oil adsorbed or absorbed on algae may be passed on to herbivorous invertebrates (Burns and Teal, 1971). This entranceway into food chains may cause a host of problems, or may be mitigated by depuration by higher trophic levels. The kelp beds of California may suffer an adverse impact from an oil spill.

(2) Bays and Estuaries

Largely depending on the quantity and composition of oil spills, differing impacts may be expected which are directly related to oil concentrations near the spill area. Large spills such as those resulting from tanker accidents, have demonstrated that definite biological damage can result from exposure of living organisms to high concentrations of petroleum hydrocarbons. For example, when the *Tampico-Maru* ran aground off the coast of Baja, California in 1957, 50,000 to 60,000 barrels of diesel fuel caused widespread mortality among many benthic organisms of the area. These animals included lobsters, abalones, sea urchins, starfish, mussels, clams and smaller forms. Such damage occurred along the shoreline and up to depths of 15 to 25 feet (North, 1973; Ketchum, 1973). Recovery occurred gradually over several years' time and began with a profuse bloom of subtidal algae within four months after the wreck (North, 1973). This latter development probably resulted from the absence of grazing animals which had been eliminated by the spill, and is a symptom of degradation, not a sign of recovery. The diesel fuel of the *Tampico-Maru* would be considered more toxic than the crude oil produced by offshore drilling operations because it contained a greater concentration of aromatic hydrocarbons. Petroleum which contains a greater amount of aromatics are usually considered more toxic (R. C. Clark, 1973). However, both crude oils and their refined products contain compounds that are toxic to species of marine organisms (Ketchum, 1973).

Bays and estuaries are usually highly productive ecosystems. Detrimental effects upon the primary productivity of these ecosystems would result in a decrease in the planktonic food supply of the large menhaden, shrimp and other fisheries in addition to directly toxic effects of crude petroleum on the fauna and flora. Ketchum (1973) cautioned that while effects of petroleum depend upon proximity to and type of oil released, "Any release of oil into the environment carries a threat of destruction and constitutes a danger to world fisheries."

However, other authors believe the adverse effects of petroleum hydrocarbons on the biotic communities of Louisiana (where oil and gas development have been the most intensive) are less significant.

St. Amant (1973), speaking of the oil producing structures in the bays, offshore areas and marshes of Louisiana, stated:

> "Louisiana's coastal areas with more than 25,000 producing wells, with some fields that have been in production for more than 40 years, and most of which has existed for 20 years, serves as a type area of high production and long-term pollution."

Yet St. Amant, aware of possible environmental damage which may result from chronic mismanagement of the environment also stated:

> "Long-term exposure in Louisiana does not seem to have resulted in significant changes in the biotic productivity of the marine system and the presence of normally occurring hydrocarbons at levels of from 100 to 500 ppm in bottom mud tend to confuse attempts to determine accumulative levels of petroleum hydrocarbons in the substrate."

While studies cited previously in this section indicate the retarding effect of petroleum on primary productivity, it is St. Amant's opinion based on his experience that there has been no decrease in overall productivity in Louisiana resulting from introduction of crude oils into the ecosystem (St. Amant, 1973).

The presence of oil consuming microbes which consume limited amounts of hydrocarbons as documented for Barataria Bay, Louisiana (Stone, 1972) may partially account for the reported lack of environmental damage.

Onuf (1973) pointed out that laboratory experiments have revealed, ". . .dislocations of normal behavior. . ." by organisms in concentrations of oil found in some polluted estuaries and that adverse synergistic interactions between low concentrations of oil and temperature/salinity stresses are of such dangerous magnitude that they warrant direct testing in the field.

> "The fact that a long period of large scale oil extracting activities has not reduced the productivity of major fisheries along the Gulf Coast of Louisiana suggests that many populations in offshore regions can accommodate long term, low level intrusions of oil. The case for estuaries cannot be so succinctly stated nor dismissed. No respectable field experiments (on estuaries) have been reported." (Onuf, ibid.)

Individual faunas have been studied for their biological responses to oil. The effects of oil on subtidal benthic communities such as those found in bays were studied by Fauchald (1971) in response to the Santa Barbara spill. One of the major organisms studied was the frequently occurring marine worm *Listriolobus pelodes* which apparently was not reduced markedly in population size. Fauchald theorized that fluctuations in numbers of benthic animals observed may have been due to natural causes or oil well drilling in the area, from the oil spill or from sewage pollution; he could not isolate the effect resulting from the spill alone.

In the *Arrow* spill study (Operation Oil, 1970), lobsters appeared to be clean and normal in behavior. Scallops taken near heavily oiled beaches had no oily taste, but chemical analysis of scallops, along with periwinkles, sea urchins, and other bottom dwelling organisms revealed that oil was present in muscle tissue, the digestive tract and other organs.

Oyster reefs are prominent developments in many bays on the Atlantic and Gulf coasts. Galtsoff (1959) noted that the major effects of industrial wastes and the soluble components of crude oil on oysters is a reduction in the rate of various physiological functions, principally ventilation of the gills. It is well known that oysters can become contaminated with oil (Erhardt, 1972; Galtsoff, op. cit.; Mackin, 1962) but there is still scientific debate as to whether oysters can cleanse themselves when returned to clean water.

Teal and Stegeman (1973) found that petroleum hydrocarbons were accumulated by two groups of oysters differing in fat content. The oysters with a higher lipid content collected that greater wet weight of hydrocarbons. When these animals were returned to clean water, the hydrocarbon content was rapidly, though incompletely, discharged. These researchers also found that the petroleum contained in the oysters differed from the contaminating oil by showing a greater percentage of aromatics. This result suggested that a higher percentage of aromatic fractions of oil were more likely to be incorporated into the oyster's tissue. The possibility that the oysters were themselves modifying the oil could not be discounted, however.

The accumulation of hydrocarbons in oyster tissue, as was demonstrated by Teal and Stegeman (1973), raises the question of petroleum hydrocarbon incorporation into other members of a food chain which eventually reach higher animals. There is, at present, no evidence that petroleum hydrocarbons are magnified in higher levels of the food chain through consumption of contaminated oysters or fish.

(3) Wetlands

Delicately balanced marshland ecosystems are subject to impacts resulting from sporadic accidental spillages and from chronic oil pollutants and pipeline construction. The greatest development of wetlands occurs on the Atlantic and Gulf coasts. In the absence of tanker operations, accidental oil discharges will be restricted to oil washed ashore from unforeseen platform accidents or pipeline rupture. Chronic pollutants may result from pipeline leaking and refinery effluents. St. Amant (1972) viewed chronic pollution as posing greater environmental jeopardy than the more obvious damage which results from accidental oil spill.

While little has been done to methodically answer ecological questions concerning effect of hydrocarbons on highly productive marshland ecosystems, some recent advances have been made. It has been established that large inputs of petroleum into marshlands may result in immediate faunal mortalities and the retarding of floral growth and diversification.

For example, British studies of salt marsh oiling followed a "moderately severe" spill of crude oil from the tanker *Chryssi P. Goulandeis* in Milford Haven estuary, Wales (Baker, 1971; Cowell, 1969; Cowell and Baker, 1969). A survey two weeks after the spill showed that oily saltmarsh vegetation had yellowed and was dying although new green growth was showing at the base of some species.

Baker (1971) sprayed saltmarshes in southwest Wales with fresh Kuwait crude oil at different times of the year. Results indicated that a light pollution with crude caused little long term damage to most salt marsh plants, whatever time of the year the pollution occurred, although most damage occurred in warm months.

Mackin, (as cited in Stone, 1972) studied the effects of crude oil on a number of Louisiana marsh grasses. The species included saltgrass, cordgrass, and Bates grass which are the dominant species in the fresh and brackish marshes. Mackin's data strongly implied that long term exposure to petroleum at relatively high concentrations is quite lethal, and that immediate and rapid cleanup is therefore critical and essential (Stone, 1972).

Boesch (1973) noted that while:

> ". . .more study and quantification are required, it seems likely that petroleum hydrocarbons, even those not soluble enough to be directly lethal, may inhibit photosynthesis for a shor time and under the proper conditions."

(4) Artificial and Hard Substrate Communities

Communities of animals on artificial and hard substrates are most common along the jetties and pilings which protect the entrances to rivers and along the pilings and boat docking structures distributed along the coast. They are also found on oil drilling and producing structures.

Although communities of anemones, limpets, molluscs, barnacles and other forms of marine/estuarine life which attach themselves to the substrate are prolific in California and New England, few of these animals have as wide a distribution in the Gulf of Mexico because of the predominantly soft-substrate beaches.

Studying the effects of the Chedabucto Bay spill of Bunker C oil, Thomas (1973) found that most of the 20 species of animals observed suffered from the effects of coating with subsequent smothering of animals but were otherwise little affected. Barnacles showed no unusual mortalities and settlement of larvae occurred in following seasons. Periwinkles, common intertidal molluscs, remained abundant and continued to occupy the same general zone. A seaweed, Fucus, however, declined over the next 10 months and, where oiling was severe, recolonization had not been successful.

Attached seaweed which declined as a result of contact with petroleum hydrocarbons dispersed from the Torrey Canyon, later recovered in the absence of grazing organisms (Stebbings, 1970).

(5) Waterfowl

In general, the types of effects of spilled oil on waterfowl are the same as on oceanic birds, viz. coating of feathers with oil and loss of heat-insulating capabilities, ingestion of toxic materials during preening of coated oil, and reduced feeding activity. Waterfowl are broadly separated from oceanic birds on the basis of their closer association with the coast and nesting areas. Waterfowl would include wading and dabbling birds, as well as diving birds. This closer association with the land subjects them to other impacts. Transport pipelines that cross beaches, marshes, and refuges cause destruction of feeding and nesting areas, as does the removal of land for the construction of pipeline terminals and treating facilities. Disruption of habits can also be caused by the human activity associated with such construction.

(6) Wildlife and Sport Fish

In general, coastal wildlife would suffer impacts similar to waterfowl as a result of pipelines crossing habitats, and construction of terminals and treating facilities. Loss of habitat from these activities could have several results. Migrations of populations from a disrupted area to a new area could cause stress from overcrowding. In some cases, suitable alternative habitats would not be available, and reductions in population sizes could begin soon after the activity began. Unfortunately, little information is available on the magnitude or even the validity of such effects.

Oil spills could also cause a disruption of isolated habitats such as island seal and bird rookeries on the western United States coast and in Alaska. The stress caused by a large spill may induce a population migration, but suitable habitats may not be readily available.

Endangered and Threatened Fish and Wildlife. A threatened species is an animal species threatened with extinction within the foreseeable future but for which the Secretary of the Interior has not, as yet officially declared (via the *Federal Register*) to be an endangered species (U.S.D.I., 1973).

An endangered species is an animal declared by the Secretary of the Interior to be in danger of extinction throughout all or a significant portion of their range. Such an animal is named on the official Endangered Species list (U.S.D.I., 1973).

Tables 77, 78, 79, and 80 list the endangered and threatened species which occur along the Atlantic, Gulf of Mexico, Pacific and Alaska coasts, respectively. The tables also list the status, distribution, and suspected cause for their designated status. A species whose status is endangered is designated by an E; those threatened are designated by a T.

THREATENED AND ENDANGERED SPECIES THAT OCCUR IN THE ATLANTIC COASTAL AREAS

COMMON NAME	SCIENTIFIC NAME	STATUS	PRESENT DISTRIBUTION	CAUSE FOR STATUS
Shortnosed sturgeon	*Acipenser brevirastrum*	E	Hudson River & Florida	Pollution
Blueback trout	*Salvelinus alpinus oquassa*	T	Maine	Overfishing
Roanoke bass	*Ambloplites cavifrous*	T	North Carolina and Virginia	Damming and siltation
Suwannee bass	*Micropterus notius*	T	Florida	Not known
Maryland darter	*Etheostoma sellare*	E	Maryland	Not known
Trispot darter	*Etheostoma trisella*	T	Alabama and Georgia	Artificial flooding of habitat
American croccodile	*Crocodylus acutus*	T	South Florida	Hunting, Destruction of habitat
American alligator	*Alligator mississippiensis*	E	North Carolina South	Hunting and Destruction of habitat
Eastern brown pelican	*Pelecanus occidentalis carolinensis*	T	North Carolina to Texas	Pesticide pollution
Florida great white heron	*Arder o. occidentalis*	T	Biscayne Bay to Cape Romano	Storms, Hunting
Florida everglade kite	*Rosthrhamus sociabilis plumbeus*	E	Central and South Florida	Hunting, destruction of habitat
Southern bald eagle	*Haliaeetus l. leucocephalus*	T	New Jersey to Texas	Destruction of habitat, Hunting
Eskimo curlew	*Numenius borealis*	T	New Jersey & South Carolina	Not known
Red-cockaded woodpecker	*Dendrocopos borcalis*	E	Virginia-South	Habitat destruction
American ivory-billed woodpecker	*Campehilus p. principalis*	E	Texas and Louisiana	Habitat destruction and hunting
Bachman's warbler	*Vermivora bachmanii*	T	Virginia and South Carolina	Habitat destruction
Ipswich sparrow	*Passerculus princeps*	T	Atlantic Coast	Habitat destruction
Dusky seaside sparrow	*Ammospiza migrescens*	E	Florida	Habitat destruction

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Table 77, cont.

ATLANTIC (cont')

COMMON NAME	SCIENTIFIC NAME	STATUS	PRESENT DISTRIBUTION	CAUSE FOR STATUS
Cape sable sparrow	*Ammospiza mirabilis*	E	Florida	Habitat destruction
Delmarva peninsula fox squirrel	*Sciurus tiger cinereus*	E	Maryland	Habitat destruction
Everglades fox squirrel	*Scirius niger avicennia*	T	Southwest Florida	Habitat destruction
Key Largo woodrat	*Neotoma floridana smalli*	T	Florida	Habitat destruction
Block Island meadow vole	*Microtus pennsylvanicus provectus*	T	Rhode Island	Habitat destruction
Beach meadow vole	*Microtus breweri*	T	Massachusetts	Predation, Habitat destr.
Sperm whale	*Physeter catodon*	E	Atlantic Coast	Hunting
Blue whale	*Balaenoptera musculus*	E	Atlantic Coast	Hunting
Finback whale	*Balaenoptera physalus*	E	Atlantic Coast	Hunting
Sei whale	*Balaenoptera borealis*	E	Atlantic Coast	Hunting
Humpback whale	*Megaptera novaeangliae*	E	Atlantic Coast	Hunting
Right whale	*Eubalaena gracilis*	E	Atlantic Coast	Hunting
Bowhead whale	*Balaena mysticetus*	T	N. Atlantic Coast	Hunting
Florida panther	*Felis concolor coryi*	E	Florida and Georgia	Hunting, Trapping, habitat destruction
Eastern cougar	*Felis concolor cougar*	E	Atlantic Coast	Hunting, Trapping, habitat destruction
Caribbean monk seal	*Monachus tropicalis*	E	Florida	Hunting
Florida manatee	*Trichechus manatus iatirostrus*	E	Florida	Habitat destruction

Common Name	Scientific Name	Status	Distribution	Cause for Status
Okaloosa darter	*Etheostoma okaloosoe*	E	Florida	Man induced siltation
Tuscumbia darter	*Etheostoma trisella*	T	Alabama	Man induced flooding
Pygmy sculpin	*Cottus pygmaeus*	T	Alabama	Pollution
American crocodile	*Crocodylus acutus*	T	South Florida	Hunting, destruction of habitat
American alligator	*Alligator mississippiensis*	E	South Fla. to Corpus Christi Texas	Hunting and habitat destruction
Eastern brown pelican	*Pelecanus occidentalis carolinensis*	E	N.C. to Texas	Pesticide pollution
Florida great white heron	*Aroea o. occidentalis*	E	Biscayne Bay to Cape Romano	Storms, hunting
Southern bald eagle	*Haliaeetus l. levcocepnalus*	E	N.J. to Texas	Habitat destruction, hunting
Arctic peregrine falcon	*Falco peregrinus tundrius*	E	Gulf Coast	Pesticide pollution
Mississippi sandhill crane	*Grus canrdensis pulla*	E	Mississippi	Destruction of habitat
Red-cockaded woodpecker	*Dendrocopos borcalis*	E	Gulf Coast	Destruction of habitat
American ivory-billed woodpecker	*Campehilus principalis*	E	Texas and Louisiana	Destruction of habitat, hunting

Table 78, cont.

Gulf of Mexico

Common Name	Scientific Name	Status	Distribution	Cause for Status
Bachman's warbler	*Vermivora bachmani*	E	Alabama	Habitat destruction
Red wolf	*Canis rufus*	E	Texas and Louisiana	Hunting, trapping, habitat destruction
Florida panther	*Felis concolor coryi*	E	Florida	Hunting, trapping, habitat destruction
Florida manatee	*Trichechus manatus latrirostris*	E	Florida	Hunting, habitat destruction
Key deer	*Odocoileus virginianus clavium*	E	Florida	Habitat destruction

Table 79.

Endangered and threatened wildlife species that occur in coastal regions of California, Oregon, and Washington

Common Name	Scientific Name	Status	Distribution	Reason for Status
Olympic mudminnow	*Novumbra hubbsi*	T	Olympic Penin., Wash.	Habitat change
Santa Cruz long-toed salamander	*Ambystoma macrodactylum croceum*	T	Santa Cruz, Calif.	Land development; subdivisions
San Francisco garter snake	*Thamnophis sirtalis tetrataenia*	E	San Francisco, Calif.	Land development; vegetation removal
California brown pelican	*Pelecanus occidentalis californicus*	T	Southern Calif.	Poor reproduction due thin egg shells
Tule white-fronted goose	*Anser albifrons gambelli*	T	Central Calif., north to Wash.	Small popn., vuln. to hunting
California condor	*Gymnogyps californianus*	E	Central and So. Calif.	Disturbance by man
American peregrine falcon	*Falco perigrinus anatum*	T	Calif. to Alaska	Poor reproduction and adult survival
California clapper rail	*Rallus longirostris absoletus*	T	San Francisco Bay, Calif.	Habitat reduction
Light-footed clapper rail	*Rallus longirostris levipes*	T	Southern Calif.	Habitat destruction
California black rail	*Laterallus jamaicensis coturniculus*	T	Central Calif.	Habitat reduction

Table 79, (Cont.)

Common Name	Scientific Name	Status	Distribution	Reason for Status
California least tern	*Sterna albifrons*	T	Central to Southern Calif.	Habitat reduction
Spotted owl	*Stirix occidentalis*	T	Calif. to Wash.	Habitat removal
Santa Barbara sparrow	*Melospiza melodia graminea*	E		
Morro Bay kangaroo rat	*Dipodomys heermanni morroensis*	E	Morro Bay, Calif	Habitat destruction, predation by cats
Salt marsh harvest mouse	*Reithrodontomys raviventris*	E	San Francisco, Calif.	Habitat destruction
Sperm whale	*Physeter catodon*	T	Pacific Coast	Over-exploitation
Gray whale	*Eschrichtius robustus*	T	"	"
Blue whale	*Balaenoptera musculus*	T	"	"
Finback whale	*Balaenoptera physalus*	T	"	"
Sei whale	*Balaenoptera borealis*	T	"	"
Humpback whale	*Megaptera novaeangliae*	T	"	"
Right whale	*Eubalaena glacialis*	T	"	"
Guadalupe fur seal	*Arctocephalus philippi townsendi*	E	Santa Barbara Channel Islands, Calif.	Small population

Endangered and threatened wildlife species that occur in coastal regions of Alaska.

Common Name	Scientific Name	Status	Distribution	Reason for Status
Aleutian Canada Goose	*Branta canadensis leucopareia*	E	Aleutian Islands, Western U.S.	Predation by Arctic foxes and rats.
Short-tailed Albatross	*Diomedea albatrus*	E	Gulf of Alaska	Excessive hunting for feathers
Eskimo Curlew	*Numenius borealis*	E	Formerly N.E. Alaska Now U.S. east coast	Excessive hunting
Arctic Peregrine Falcon	*Falco peregrinus tundrius*	E	Arctic Alaska, eastern and Middle No. Amer.	Population decline, due to pesticides (suspected).
American Peregrine Falcon	*F.p. anatum*	E	Non-Arctic Alaska to Baja California	As above
Sperm Whale	*Physeter catodon*	E	Pacific Ocean	Over-exploitation
Gray Whale	*Eschrichtius robustus*	E	"	"
Blue Whale	*Balaenoptera musculus*	E	"	"
Fin Whale	*Falaenoptera physalus*	E	"	"
Sei Whale	*Balaenoptera borealis*	E	"	"
Humpback Whale	*Megaptera novaenagliae*	E	"	"
Black Right Whale	*Balaena glacialis*	E	"	"
Bowhead Whale	*Balaena mysticetus*	E	"	"
Glacier Bear	*Ursus americanus emmonsii*		Glaciated Alaska, esp. near Yakutat	Over-exploitation

b. Impact on Recreational, Historical, and Archeological, Aesthetic and Conservation Resources

(1) Beach and Shoreline Recreation

If pipelines which result from a sale are brought ashore in a beach area used for recreation, there will be an impact on recreational activities. The area of a beach disturbed by pipeline construction will be small (about 30-50 feet wide), and the first high tides following burial of the pipeline will serve to restore the beach terrain. Restoration of the beach ridge will take longer, most likely requiring a storm tide or high winds to obliterate the effects of excavation. Physical interference with recreational activities from excavation will be minimal and short-lived.

If pipeline terminal or transfer facilities are located in or near a beach or other area used for recreation, there will be an adverse impact on recreational activities from disruption during the construction phase and elimination of about 40 acres per terminal plant for recreational uses. This latter impact would be long-term and restoration of the area, if attempted at all, would have to await depletion of the offshore production which the plant would be designed to serve. These impacts will diminish the quality of the area for recreational enjoyment.

The impacts of pipeline and terminal facilities construction on recreation would be mitigated somewhat if the appropriate governmental authorities were to allow this type of construction only during the time when recreational use of the area is at its lowest point.

The impacts from permanent terminal facilities could be mitigated somewhat by locating them at some distance inland where recreational use is not intense. State authorities may wish to consider this alternative.

Water sports, such as swimming, diving, spearfishing, underwater photography, fishing for finfish and shellfish, boating and water skiing would also be directly affected by an oil spill.

Other seashore related activities such as beachcombing, shell collecting, painting, shoreline nature study, camping and sunbathing would be made much less attractive for an indeterminate period where an oil spill had coated a beach.

Removal of oil from beaches used for recreation in the area under consideration would probably involve removal of the contaminated sand and possibly, replacement of the sand if needed. The time required for clean-up in this case would depend on the extent of beach affected. Recreational use of the area would be precluded during the time that oil covered the beach and during the clean-up process also.

The impacts of an oil spill discussed above would be more keenly felt if the recreation area involved is intensively used or considered to have unique or outstanding recreational values. Not only would the impact be felt by the recreational users of these areas but, consequently, the community of businesses whose economic well-being depends on use of their recreational resources by tourists would be affected. If an oil spill were to cover outstanding recreational beaches during the height of the recreational season, the impact could be expected to be more severe, in that residents and tourists would not be attracted to a beach area contaminated by oil or undergoing a clean-up process, and there would be a resultant economic loss.

(2) Aesthetic and Scenic Values

If air quality permits unlimited visibility, some portion of a one hundred foot structure can be seen from the beach if it is located 17 miles or less from shore. Some people consider the sight of offshore equipment aesthetically unpleasant.

Any floating material such as debris or oil that is cast up on the beach or washed into a bay would constitute an impact upon the aesthetic values for users or owners of the area.

Even after burial of the pipeline, the scars will cause an impact on the aesthetic values of the beach and associated dunes and sand flats. It is our estimation that the impact will endure for at least a year, until sand has been redistributed by wind, and tides, and another growing season brings about revegetation.

Revegetation of dunes crossed by pipelines would reduce adverse effects from an aesthetic and scenic viewpoint and would decrease the chance of destruction of the dunes by erosion. It is not, however, within the Federal Government's authority to require the revegetation of affected dunes unless they are on Federal lands. State or local authorities may require require revegetation of dunes disrupted by pipeline installations.

There will be an adverse impact on aesthetic and scenic values resulting from construction of onshore terminal and product storage facilities, and pumping stations if these facilities are located in areas valued for their natural or scenic qualities. Some people will find the visual impact of these facilities aesthetically displeasing. There also may be noise pollution associated with vehicular traffic to and from these facilities and noise pollution resulting from pumping stations that would reduce the serene and natural qualities of an aesthetically enjoyable area.

(3) Historical or Archeological Sites and Objects

Impacts on these could stem from two sources. During an oil spill, any objects coated with oil would obviously be rendered less useful and valuable and may not survive cleaning operations. In addition, porous items such as wood, pottery, or shell may be internally contaminated with oil and this might interfere with carbon dating procedures.

During pipeline burial operations or construction of terminal, storage, or pumping facilities, as yet undiscovered archeological sites or objects and shipwrecks may be damaged or destroyed. Normal pipeline route survey procedures usually include a magnetometer survey. In this way, all larger ferrous objects, including objects of historic or archeological value, are detected and avoided or investigated prior to actual laying operations. This survey would not reveal the presence of nonferrous objects, however. Therefore, it is likely that sites containing archeological evidence of cultures which did not make use of metal, i.e., the older, less well-known cultures, would not be detected by this method.

Special surveys of onshore facility site locations and pipeline routes would have to be taken before any assurance that sites and objects of historical or archeological interest might not be destroyed or damaged.

Pipeline burial operations have the potential for damage or accidental destruction of as yet undiscovered sites which may be important to the understanding of prehistoric inhabitants of the area. The scope of the impact and its probability of occurrence is not possible to determine at this time. The impact may be mitigated to some degree if the appropriate state authorities are consulted as to the exact locations of known archeological sites or potential locations for undiscovered sites before any construction or pipeline burial is undertaken.

(4.) Conservation Resources

Included under this heading are the state and Federa wildlife refuges and management areas, natural landmarks and any other areas formally set aside for conservation of their natural values. There are a number of areas of this type adjacent to the coastline.

The impacts of oil spills and pipeline and onshore facility construction on biota, air and water quality, beaches, etc., have been discussed previously. Should an oil spill occur in a conservation area, or should pipeline and onshore facility construction occur in one of these areas, the impacts discussed above will apply. In the event that impacts discussed previously do occur in a conservation area, the impact will not only be on the air and water quality, beaches, biota, etc., the impact will also be on the effort to preserve or protect a unique, representative, or otherwise significant natural value.

(5) Sport Fishing

Although we have no conclusive evidence, it is our opinion that a major oil spill would affect sport fishing adversely. Boat fishermen would not want to soil their boats by fishing in the vicinity of an oil slick and neither boat nor surf fishermen would want to keep fish that had been coated or contaminated with oil. Therefore, sport fishing would be curtailed in the vicinity and for the duration of the spill incident.

We have received extensive testimony and evidence that overall, oil and gas operations have a favorable impact on sport fishing activities. The favorable impact is the result of sports fish population enhancement due to the artificial reef effect on offshore platforms. In the open sea, offshore platforms provide both food and cover in areas that are largely devoid of those essentials. Myriad forms of microorganisms in the water drift by these structures and attach themselves, soon encrusting all exposed surfaces on the platform. The average platform in 150 feet of water provides 90,000 square feet of hard surface for encrusting organisms. [1] Hard substrate is necessary for encrusting organisms such as barnacles, hydroids, corals, mussels, and other invertebrate organisms which serve as links in the food chain. Randall (1963) has stated that artificial reefs provide protection, food sources, spawning sites, and spatial orientation markers for fishes. The same author found that artificial reefs attract available fish from surrounding waters, and increase the size of some populations by providing additional protected areas and food for both young and adults.

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[1] Information from Keith G. Hay, Conservation Director, American Petroleum Institute.

c. Land Use and Socio-Economic Effects on Onshore Development

This section examining the onshore impacts of OCS activity is primarily drawn from Chapter 7 of OCS Oil and Gas - An Environmental Assessment, published by the Council on Environmental Quality, April 1974. That chapter of the CEQ report is based largely on a contract study undertaken for CEQ by Resource Planning Associates, Inc. (RPA) entitled "Potential Onshore Effects of Oil and Gas Production on the Atlantic and Gulf of Alaska Outer Continental Shelf." This section also contains data and analysis from environmental assessment teams in OCS regional offices in Los Angeles, New Orleans, Anchorage, and New York.

As the development of offshore oil and gas proceeds from the intial exploratory phase through drilling, production, and transportation, substantial onshore activity will be generated, from which both positive and negative impacts can be expected. Refineries, petrochemical complexes, construction industries, and related service operations increase employment opportunities, economic output, and income, but the growth that they cause will strain existing public services, bring additional land under commercial, residential, and industrial development, and add to air and water pollution.

The RPA study is based on a set of complex geographical and industrial development assumptions for each region examined. The assumptions concern the sites selected and estimates of industrial development and production. It is important to note that the sites were selected for analytical purposes only. The intent of the study was to illustrate and provide an understanding of the range of economic, social and environmental impacts of onshore development resulting from OCS development and production. It is not intended as a prediction of what will actually happen in a specific locale. The reader is referred to the cited RPA report for a full description of the assumptions used in site selection and development assessments.

The selected sites are all listed in Table 81 , and the locations of the ones chosen for analysis are shown in Figures 127 and 128 . The counties chosen are those where oil and gas could be brought ashore; where refinery, gas processing, petrochemical, and construction activities would develop, and for which socio-economic and environmental data are obtainable. The derived production estimates are shown in Table .

Table 81. Hypothetical Onshore Development Areas Considered for Analysis

East Coast Hypothetical Receipt Points
- Eastport, Me.
- Bangor, Me.
- Portland, Me.
- Boston, Mass.
- Bristol County, Mass.*
- Narragansett Bay, R.I.
- Long Island, N.Y.
- Raritan Bay, N.J.
- Cumberland/Cape May Counties, N.J.*
- Baltimore, Md.
- Chincoteague Bay, Md.
- Hampton Roads, Va.
- Albemarle Sound, N.C.
- Georgetown, S.C.
- Charleston, S.C.*
- Beaufort, S.C.
- Savannah, Ga.
- St. Catherine's and Sapelo Sound, Ga.
- Jacksonville, Fla.*
- Brevard County, Fla.
- Stuard, Fla.

West Coast Hypothetical Refining Sites
- Puget Sound, Wash.*
- Columbia River Inlet, Ore.
- San Francisco Bay area, Calif.*
- Monterey Bay, Calif.
- Los Angeles, Long Beach, Calif.

Alaska Hypothetical Receiving and Transshipment Sites
- Yakutat Bay
- Cordova*
- Valdez*
- Anchorage
- Seward
- Kodiak Island
- Kenai
- Katalla

*Sites chosen for analysis.

WEST COAST SAMPLE
HYPOTHETICAL OCS

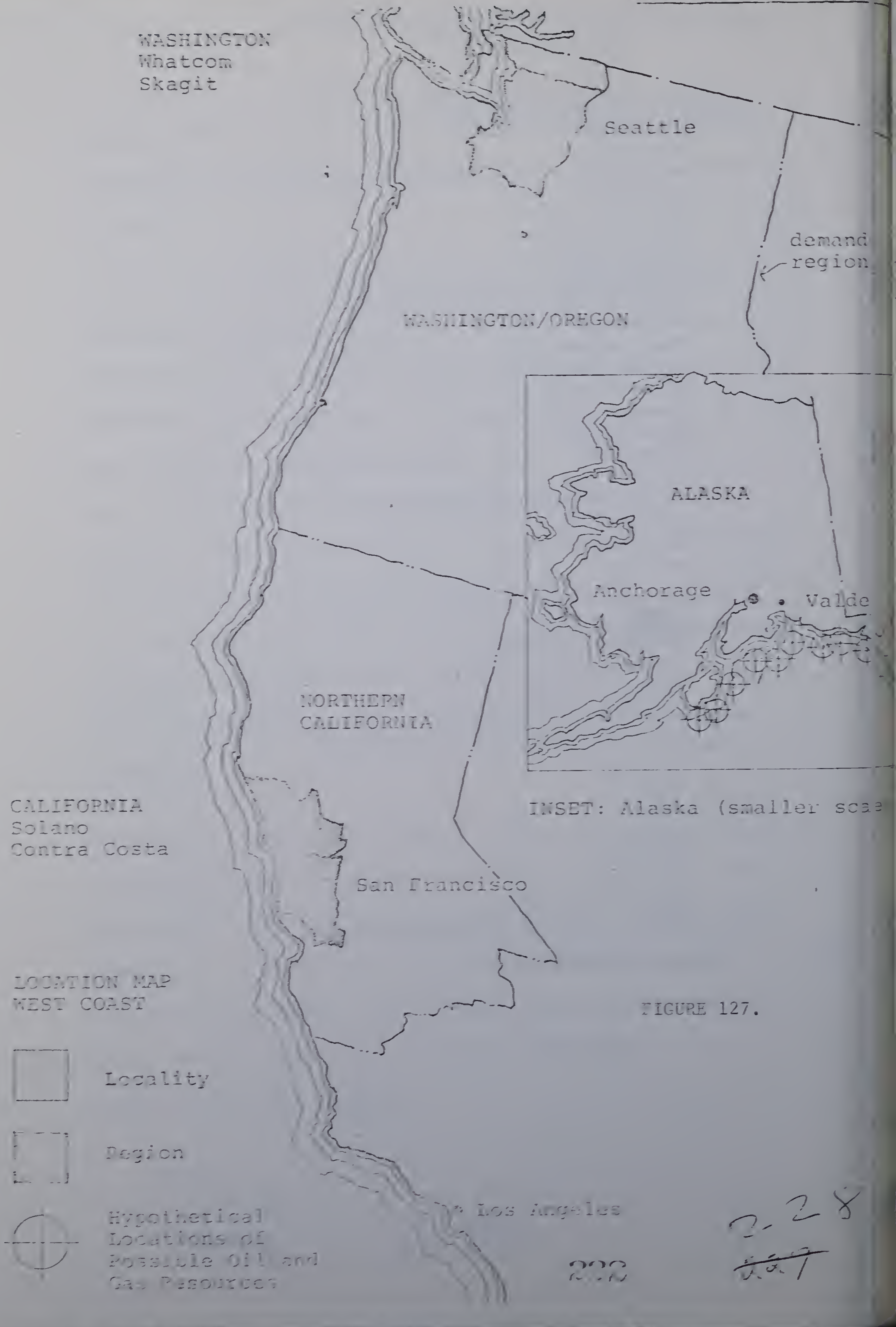

FIGURE 127.

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ATLANTIC SAMPLE SITES & HYPOTHETICAL OCS LOCATIONS

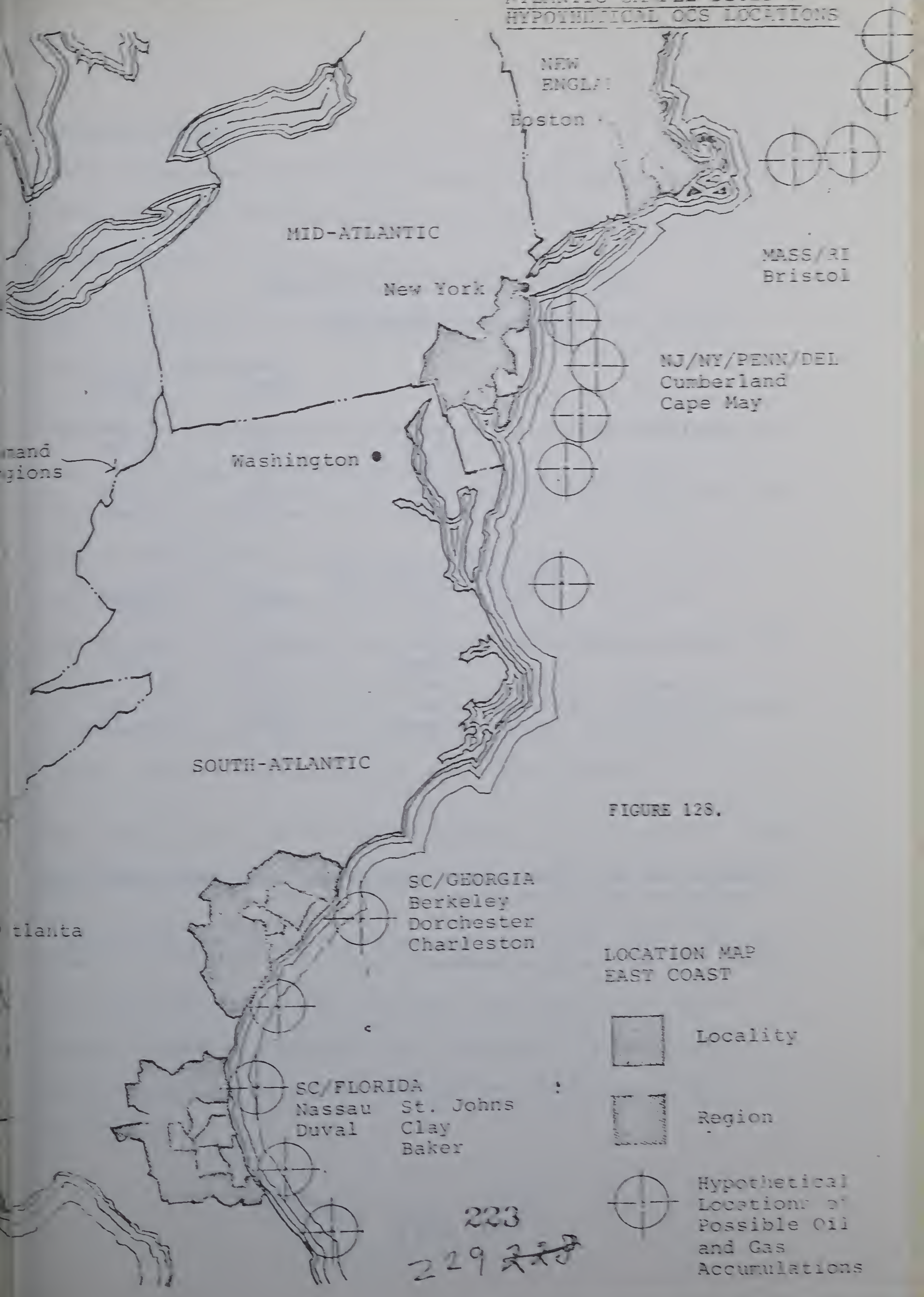

FIGURE 128.

OFFSHORE PRODUCTION ESTIMATES

ATLANTIC COAST OCS[a]

		1985	2000
Oil (million bbl/day)	Low	0.25	0.50
	High	0.75	1.50
Gas (billion cu.ft./day)	Low	0.30	1.80
	High	0.90	3.60

GULF OF ALASKA OCS

		1985	2000
Oil (million bbl/day)	Low	0.25	1.00
	High	0.75	2.00
Gas (billion cu.ft./day)	Low	0.30	2.40
	High	0.90	7.20

[a] Estimates are for each of the three potential producing areas in the Atlantic OCS

Source: RPA and CEQ estimates based on USGS projections of resource levels.

Method of Analysis

Onshore impacts were predicted by comparing normal growth, no OCS development with induced growth stimulated by OCS development and production.

Base case estimates of normal growth, were compared with estimated OCS induced development.

Owing to the absence of OCS production on the east coast the two base cases used reflect greater uncertainty. Both cases assume continued oil imports and exclude OCS production. Base Case 1 doubles onsite refinery capacity to 3 million barrels per day by the year 2000. It assumes that no new "grassroots" refineries will be sited, and it depends more on Gulf coast and imported refined products. While this case does not reflect the lowest growth possible, it takes into account the demand projections in Chapter 3 and the expected need for more refinery capacity.

Base Case 2 assumes construction of deepwater ports in each of the three east coast demand areas (New England, Mid-Atlantic, and South Atlantic) that will serve the nearly fivefold increase in refining capacity from 1975 to 2000 -- over 7 million barrels per day. This case assumes that each region approaches a 50 percent self-sufficient refinery capacity by 2000 -- a goal that may be impossible for New England and the South Atlantic without extensive new refinery siting and growth.

Because the west coast (PAD V) is now virtually self-sufficient and has refineries in several locations, refinery growth is more predictable. Therefore only one base case was analyzed. Under the case, refining capacity is expected to increase from today's 2.2 million barrels to 3 million per day by 2000. No refineries are assumed for Alaska because of the small market for refined products there and the economic advantage of shipping crude oil to refineries near the large west coast markets. In each PAD V demand area, added refinery capacity was estimated only to the point of self-sufficiency for the area.

This study assumes that all Gulf of Alaska crude oil going to the Puget Sound and San Francisco regions will require additional refining capacity beyond that constructed for North Slope or imported crude. To the extent that Gulf of Alaska replaces North Slope or imported crude, the impacts outlined here are overstated.

The reader is referred to the cited CEQ or RPA report for a full explanation of other assumptions for the base cases as well as the assumptions made in estimating oil and gas production levels.

Impact Findings

The estimated impacts for high-level OCS production are shown in Tables 82 and 83 . The tables show offshore platforms, refineries, gas processing plants, petrochemical complexes, value of construction, employment, population, and acreage.

Resource Planning Associates summary impact conclusions are as follows:

> There are three general findings which help to place the more detailed findings in perspective. First, significant refinery and petrochemical industry in conjunction with dispersed deepwater terminals to receive oil imports, is expected prior to OCS development. This growth should have roughly the same impact in each locality and region as the onshore impact from high OCS development. More importantly, the manner in which localities and regions handle import-induced growth should set the stage for the later OCS-induced development.
>
> Second, the oil-induced OCS development should be much more significant (perhaps 10 to 20 times more) than the gas-induced development in terms of economic output and employment, land requirements, and likely pollution emissions. This sharp difference in impacts occurs because refineries will (1) require much greater human and physical resources than gas processing plants, and (2) induce more petrochemical development than gas plants.
>
> Third, a comprehensive regional planning effort will be required to properly integrate OCS-induced development into a regional economy. This will be necessary to (1) provide a balanced land use pattern, (2) site the industrial facilities in a way that minimizes

TABLE 82.

Summary of Onshore Impacts, East Coast: High Development[1]

Key impacts	New England				Mid-Atlantic			
	1985		2000		1985		2000	
	Local	Region	Local	Region	Local	Region	Local	Region
Primary impacts								
Number of offshore platforms (25,000 barrels per day)	38	38	68	68	38	38	68	68
Number of refinery equivalents (200,000 barrels per day)	1.4	2.8	2.8	5.6	1.9	4.2	2.8	7.2
Number of gas processing plants (500 million cubic feet per day)	2	2	4	8	2	2	4	8
Number of petrochemical complex equivalents (1 billion pounds per year olefins)	0	0.5	0.8	2.4	1.0	2.2	1.9	6.0
Value of incremental construction (millions of 1970 dollars)	196	387	79	155	118	332	7	84
Aggregate impacts								
Employment (thousands)	19.0 (9)	76.7 (3)	17.3 (7)	83.1 (3)	28.8 (19-30)	100.2 (2)	31.9 (20-29)	120.8 (2)
Population (thousands)	43.6 (9)	188.8 (3)	38.8 (7)	191.7 (3)	59.6 (19-27)	227.0 (2)	66.0 (19-26)	268.6 (2)
Acreage required (thousands)	7.0 (8-9)	24.3 (3)	8.0 (9)	26.9 (3)	32.4 (18-26)	49.3 (4)	35.5 (18-25)	57.0 (4)
Hydrocarbon loadings (thousand tons per year)	16.6 (592)	36.6 (6-8)	34.6 (1116)	71.9 (87-134)	27.3 (41-273)	57.3 (7-14)	40.2 (41-338)	103.6 (11-27)
Biological oxygen demand (million tons per year)	0.9 (14)	3.2 (5)	1.8 (23)	5.7 (6)	1.6 (29-68)	4.3 (4)	2.4 (30-104)	7.8 (6)

See footnotes at end of table.

TABLE 32.—*Continued*

Summary of Onshore Impacts, East Coast: High Development

Key impacts	South Atlantic/Charleston				South Atlantic/Jacksonville			
	1985		2000		1985		2000	
	Local	Region	Local	Region	Local	Region	Local	Region
Primary impacts								
Number of offshore platforms (25,000 barrels per day)	38	38	68	68	38	38	68	68
Number of refinery equivalents (200,000 barrels per day)	1.4	2.8	2.8	5.6	1.4	1.4	2.8	4.2
Number of gas processing plants (500 million cubic feet per day)	2	2	4	8	2	2	4	8
Number of petrochemical complex equivalents (1 billion pounds per year olefins)	1.2	2.4	4.2	7.4	0	0	4.2	5.8
Value of incremental construction (millions of 1970 dollars)	228	405	91	162	271	434	108	174
Aggregate impacts								
Employment (thousands)	59.2 (29-41)	87.9 (19-24)	75.8 (28-38)	109.9 (20-25)	37.0 (9-10)	53.9 (11-12)	58.7 (12-13)	84.6 (14-16)
Population (thousands)	137.5 (27-34)	250.8 (20-25)	145.4 (24-31)	272.9 (20-25)	82.3 (9)	142.3 (12-13)	111.2 (10)	202.4 (15-16)
Acreage required (thousands)	26.0 (24-29)	64.6 (16-18)	29.6 (23-29)	75.4 (17-20)	25.4 (7-8)	43.2 (9-10)	33.3 (8-9)	64.9 (11-14)
Hydrocarbon loadings (thousand tons per year)	24.5 (75-150)	48.4 (44-111)	47.6 (11-24)	94.9 (62-175)	17.6 (73-149)	21.2 (43-64)	43.2 (111-294)	71.8 (73-156)
Biological oxygen demand (million tons per year)	2.1 (53-78)	5.6 (23-44)	4.3 (81-120)	10.8 (37-60)	2.8 (13-15)	3.8 (15-17)	8.1 (25-31)	11.7 (28-36)

[1] All impacts are over base case conditions. The numbers in parentheses represent percentages over base case conditions, the first over Base Case 2 and the second over Base Case 1; where there is only one number, the percentage increase is the same for either base case.

Source: Resource Planning Associates, Inc., and David M. Dornbusch & Co., 1974, "Potential Onshore Effects of Oil and Gas Production on the Atlantic and Gulf of Alaska Outer Continental Shelf," prepared for the Council on Environmental Quality under contract No. EQ4AC002.

TABLE 83.

Summary of Onshore Impacts, West Coast: High Development[1]

Key impacts	Alaska				Washington/Oregon				Northern California			
	1985		2000		1985		2000		1985		2000	
	Local	Region	Local	Region	Local	Region	Local	Region	Local	Region	Local	Region
Primary impacts												
Number of offshore platforms (25,000 barrels per day)	19	19	60	60	NA	NA	NA	NA	NA	NA	NA	NA
Number of refinery equivalents (200,000 barrels per day)		0		0	0.1	0.1	1.3	1.3	1.3	1.3	3.5	3.5
Number of gas processing plants (500 million cubic feet per day)		2		16	0	0	0	0	0	0	0	0
Number of petrochemical complex equivalents (1 billion pounds per year olefins)		0		0	0	0	3.0	3.0	0.5	0.5	2.9	2.9
Value of incremental construction (millions of 1970 dollars)		55		21	214	214	86	86	194	194	78	78
Aggregate impacts												
Employment (thousands)		4.4 (2)		3.7 (1)	11.0 (17)	17.3 (2)	16.5 (19)	32.2 (2)	16.4 (6)	28.3 (1)	22.0 (5)	42.7 (1)
Population (thousands)		16.0 (4)		12.9 (2)	22.0 (15)	39.0 (2)	31.4 (17)	71.0 (2)	33.7 (3)	67.3 (1)	42.4 (3)	97.0 (1)
Acreage required (thousands)		NA		NA	8.1 (12)	10.8 (2)	13.2 (16)	18.5 (3)	5.2 (3)	7.3 (1)	7.8 (4)	10.9 (2)
Hydrocarbon loadings (thousand tons per year)	NA	NA	NA	NA	1.7 (3)	1.8 (2)	23.4 (42)	23.6 (18)	15.1 (21)	15.5 (11)	43.3 (48)	43.7 (25)
Biological oxygen demand (million tons per year)	NA	NA	NA	NA	0.2 (7)	0.7 (1)	2.2 (53)	3.7 (4)	1.3 (15)	1.8 (2)	3.8 (12)	4.6 (3)

[1] All imports are over base case conditions. The numbers in parentheses represent percentages over base case conditions, the first over Base Case 2 and the second over Base Case 1; where there is only one number, the percentage increase is the same for either base case.

Source: Resource Planning Associates, Inc., and David M. Dornbusch & Co., 1974, "Potential Onshore Effects of Oil and Gas Production on the Atlantic and Gulf of Alaska Outer Continental Shelf," prepared for the Council on Environmental Quality under contract No. EQ4AC002.

pollution levels, and (3) develop infrastructure facilities and services to support the population induced by onshore OCS development. Since the planning effort must come in advance of the new governmental revenues that OCS development could bring, Federal or state planning support will likely be required. This support will be particularly important for less developed areas or areas with limited governmental planning and administrative capabilities.

In addition to these overall findings, the following sections discuss the major economic, social infrastructure, and land use, impact findings.

Area Analysis

A detailed analysis of each region studied by RPA indicated that substantial portions of the undeveloped land were not suitable for general or primary industry development due to environmental constraints (e.g. wetlands, ecological sanctuaries, national parks and seashores, and coastal recreation areas), locational constraints (e.g., excessive slopes, inadequate water, and distance from major population centers), and factors such as agricultural requirements and low density development.

High OCS development was projected to require from 10,000 to 75,000 acres in the sample regions analyzed. Excluding land unavailable for development due to the above factors results in significant problems for base case and OCS - induced land requirements in some regions. RPA noted that it may be extremely difficult to find enough land in the San Francisco Bay and Puget Sound regions for base case and OCS - induced growth. Environmental and locational constraints remove about 90 percent of the undeveloped land in the San Francisco Bay region. Land in some of the potential Alaska staging areas is scarce due to land configuration, native claims, and location of natural areas. RPA concluded that moderate land use planning problems are also projected for the New England, Mid-Atlantic, and South Atlantic regions.

The RPA report emphasizes the problem of finding adequate sites in almost every region and the importance of advance regional land use planning. CEQ's report emphasized the point that primary industry need not develop adjacent to offshore production areas. New refining and industry sites may be determined more by what land is available than by location alone. In some regions inland locations would be better suited environmentally than the more fragile coastal areas.

East Coast

New England

RPA concludes that for the sample region studied (Eastern Massachusetts and Rhode Island) the acreage required for high level production and OCS development represents 17 percent of the undeveloped land actually suitable for primary development (e.g. specialized and heavy industrial uses - refineries petrochemical complexes, etc.)

Mid-Atlantic

For the study area of the Delaware River region (Delaware, Pennsylvania, New Jersey, and New York), high OCS development would require 21 percent of the suitable developable land and this percentage would increase further if suburban development and as yet unknown environmental impoundment areas were considered.

South Atlantic

By the year 2000 about 10 percent of all suitably developable acres will be required for high base case and OCS - induced growth according to RPA's findings in the Eastern South Carolina/Eastern Georgia region.

In the Northeastern Florida/Southeastern Georgia region about 11 percen of the developable acres may be required for the high base case and high OCS development.

West Coast

Alaska - Gulf Region

Sufficient developable land exists for even the high development cases, projected to the year 2000 by RPA.

Puget Sound Region

About 70 percent of suitably developable land would be required by the year 2000 under the high base case high OCS - induced development. It would be very difficult to find adequate land under the extreme high development assumptions.

San Francisco Bay Area

In this region only limited acreage is actually available and suitable for primary development. It is unlikely that sufficent land will be available base case growth and OCS - induced growth. RPA concluded that unless significant rezoning is done, it appears as if the amount of base case and OCS - induced development will have to be reduced in the San Francisco Bay region.

Southern California

This region was not studied by RPA. The following discussion was developed by BLM.

New refineries will probably be located in proximity to existing ones in order to realize the economics of utilizing pipeline facilities. The following map outlines the location of existing refineries and pipelines in PAD V. The refineries in California are located south of San Francisco with the majority located in the Los Angeles basin. New facilities will tend to aggregate in these regions. Only one refinery is located in Oregon with several situated in the Puget Sound region.

A major new refinery utilizes between 200 and 1,000 acres of land for a design capacity of 100,000 barrels per day (Corps of Engineers, 1973). For a design capacity of 200,000 barrels per day the area requirements are between 500 and 1,700 acres. The Corps of Engineers reported in 1973 that there is a shortage of sites for new refineries within the Los Angeles basin.

The lack of space does not constitute an absolute limit on the expansion of refinery capacity, since an increase can be realized by replacing obsolete units with more efficient units. There is virtually

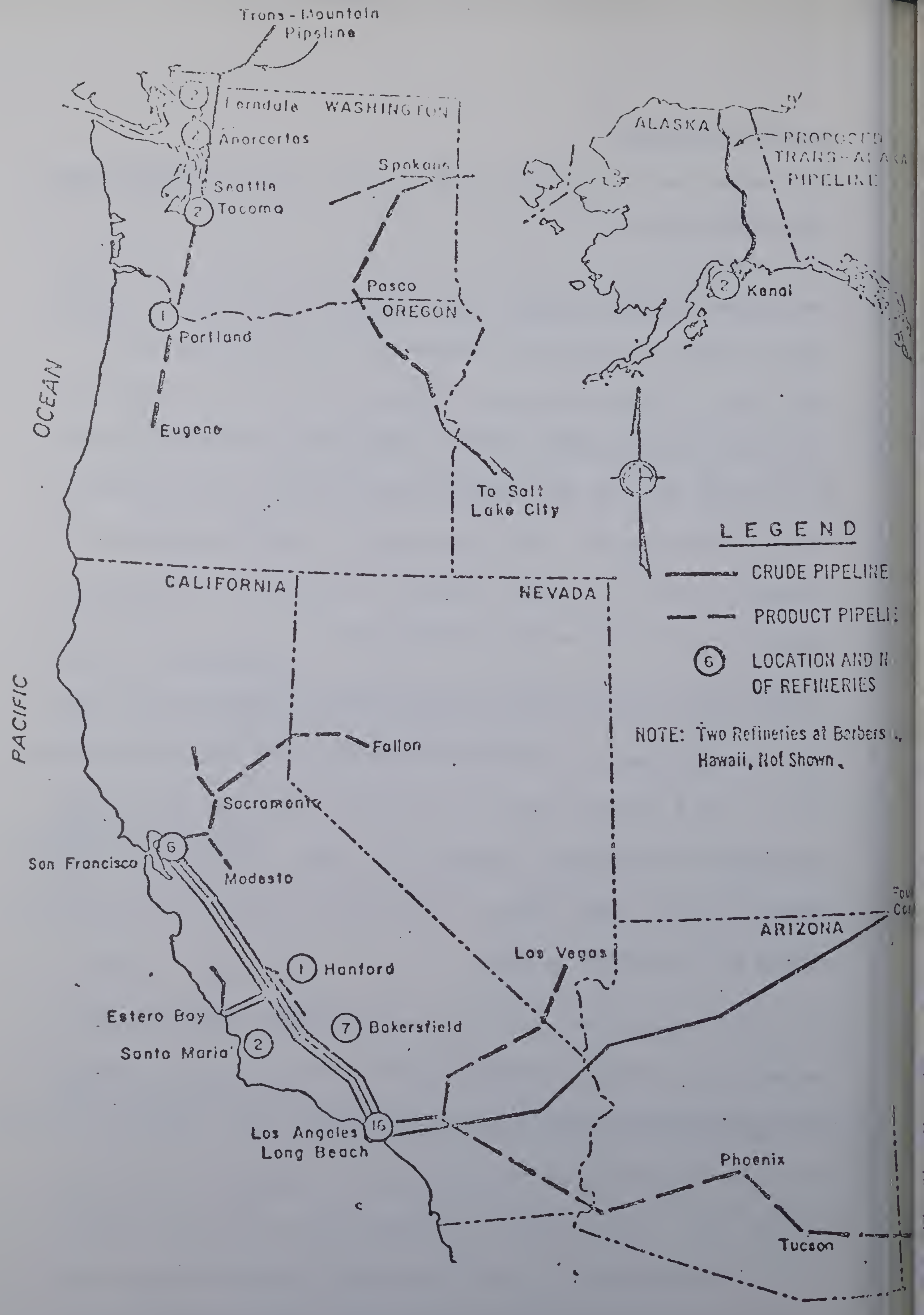

Figure 129. EXISTING REFINERIES, CRUDE AND PRODUCT PIPELINES, PAD V

no vacant land at El Segundo, California; however, a large increase in capacity is planned by replacing obsolete facilities.

Gulf of Mexico

This analysis was made by BLM. The impacts on land use in the Gulf region of additional OCS development would be incremental due to the extensive facilities already in existence.

Gulf-wide, there is great variability in the existing level of gas and oil production and related activity, and the resulting support and service infrastructure which has developed. Portions of the Texas and Louisiana coastal zones have developed a nearly self-contained gas and oil related infrastructure in the form of service, support, production, transportation, storage, processing etc. facilities. The Mississippi and Alabama coasts have a much lower level of development, and the Florida Gulf coast has experienced very little onshore and no offshore gas and oil production, and have almost no infrastructure development. The activities and facilities required to support the offshore lease program will therefore fall partly within the framework of a frontier area which possesses no such capabilities. The regional impact of and response to the program could be highly variable and at least partly a function of these existing differences in the infrastructure levels in proximity to the production areas.

Many references indicate that in recent years the extension of gas and oil production into offshore areas along the Texas and Louisiana coast has served to offset the decline in productivity and proven reserves onshore. This suggests that at least portions of the existing infrastructure are operating at less than full capacity, and that some of this presently underutilized potential may be able to absorb much of the normal program-related inducements.

Program inducements are not generally expected to overload this existing or historic capacity, except possibly during certain years when cumulative sale activity and productivity peaks. Should the program thus cause incremental increases in any segment of the infrastructure, such increases are likely to occur in presently industrialized areas, probably through more intense use of lands already dedicated to such uses.

Existing land development and activities related to the oil and gas industries are expected to be strong locational factors influencing program related land-use inducements. Areas presently committed to a highly developed gas and oil related infrastructure are expected to have a greater tendency towards, and land use precommittment to, - expansion of these activities than will those areas with a low or non-existent level of development. Accordingly, since the Central and Western Gulf include gas and oil related services and general industrial areas such as Corpus Christi, Houston-Galveston, St. Charles, New Orleans-Baton Rouge, Pascagoula and Mobile, it can be assumed that these areas will be focal points for the service and support requirements of the program.

A wide variety of supply and service industries are required which have capabilities to support the exploration, production and transportation of gas and oil. These include companies dealing with tools, wireline, gas life, cement, boats, etc., as well as machine and welding shops, trucking firms, wellhead and mud suppliers, supply stores, air and marine transport services. Such capability is typically present in many industrialized areas through the Central and Western Gulf coastal zone, and it has been assumed that excess capabilities exist in these sectors which will be stimulated and utilized by production-related demands. It is not anticipated that the program will create a significant demand for new lands dedicated to these uses. If new pipeline landfalls are required as a result of the program, they are typically accompanied by separator and condensate storage facilities for the gas lines, and possible storage facilities for oil lines. Such inducements are small in their acreage requirements.

As mentioned, there is virtually no existing gas and oil related infrastructure in the Eastern Gulf. The Florida Gulf coastline, with few exceptions, does not have the capability to service or support oil and gas related activities or demands. Such demands therefore, should they be developed in Florida, would result in 1 : 1 incremental land use demands. However, as previously mentioned the location of onshore responses is loosely related to oil and gas industries are expected to be strong locational factors influencing program related land use inducements.

The significance of this for Florida is that the magnitude and pattern of onshore industrial inducements resulting from development of its "frontier" offshore area will be strongly affected by its proximity to the highly developed infrastructure in the Central Gulf. Existing gas and oil transport, storage and processing capabilities and the general level of industrial development in Alabama and Mississippi, and especially Louisiana, will tend to attract production via pipelines from much of the area offshore Florida. This tendency will be in lieu of creating new infrastructures in Florida due to directing that production immediately onshore for processing.

Scenarios could, of course, be developed which would lead to significant onshore inducements in Florida. These would involve the finding of massive hydrocarbon reserves at significant distances from existing infrastructures. In such cases, if levels of production justified the massive capital expenditures required, it is reasonable to expect development of totally new infrastructures closer to the origin of production.

The total program induced acreage is assumed to be modest, and these land use requirements may be widely dispersed over large portions of the Gulf coastal zone. It can be assumed that this gross region has many site alternatives which could host the acreage requirements and locations, both of which could be quite variable.

Socio-Economic Impacts

Economic Impacts

The OCS development will induce significant economic impacts in localities and regions surrounding the location of primary sector industries such as refining and petrochemicals. For example, as many as 75,000 new jobs by the year 2000 were projected by RPA to exist in a single locality in conjunction with high OCS development. In a broader regional area, new employment could reach 120,000. These figures would represent increases in employment of as much as 40 percent over base case projections for a locality and 25 percent for a region overall. The largest employment increases were projected for the Charleston, S. C. locality and the Eastern S. C./ Eastern Ga. region.

Not all areas, however, would receive impacts of this size. In New England less than 20,000 new jobs would be created in the locality and about 80,000 in the region under high impact development. The West Coast impacts would be even smaller. About 20,000 new jobs are projected in a locality but generally no more than 40,000 for the regions. In Alaska, Valdez could expect about 1,000 new jobs, with the entire state gaining between 4,000 and 5,000 under high OCS development assumptions.

Of the five industrial sectors which were analyzed by RPA (oil and gas recovery, gas processing, refining, petrochemical, and construction), the construction sector in 1985 and the petrochemical sector in the year 2000 were the biggest employers. A maximum construction employment in the 1980's is assumed to support the rapid refining, gas processing, and petrochemical development that would occur as OCS production was building to its peak in the 1990's. The demand for labor (in 1985) is projected enough above base case levels that shortages of men skilled in certain specialities, particularly in construction, could exist.

Additionally, refining, petrochemicals and construction generate significant amounts of employment in other industries. The largest portion of this employment shows up in the service sector, with lesser amounts in other manufacturing and utilities.

The analysis indicates that under low OCS expansion, the level of new economic activity would be roughly one-third to one-half of the high impact projections. The construction sector would remain the biggest primary employer in 1985, but with much less risk of labor shortages. In 2000 there would be more limited petrochemical development, since the threshold levels of required refinery output (about 500,000 barrels per day) would not have been reached in some regions. The resulting refineries would be the largest primary employer in the year 2000.

Under either set of development assumptions, other important economic impacts in the localities and regions would also be felt. Perhaps most importantly, the significant demands for labor of all kinds would lower a local or regional unemployment rate relative to other sections of the nation. The same demand would cause the average wage rate of all industries within a locality (or region) to rise, especially in those areas which currently have low relative wages. All four of the sample East Coast localities are in this category. Since per capita income is directly related to earnings, the average per capita income of each locality would also rise. Thus, each area would, in one sense, be wealthier.

Moreover, special industries within each area would be affected. The amount of land devoted to agriculture could be expected to fall as the value of specific parcels of land rose. Tourism could be stimulated, at least insofar as the demand for hotels, motels and restaurants is concerned. However, recreational industries could be adversely affected.

For regions where OCS - induced development would represent a continuing activity or increment to already existing facilities, resources, and manpower as compared with regions where there has been no previous OCS activity, the impacts will be mitigated by such factors as facility capacities and external economies of aggregation, for instance, in manpower. Employment activities will utilize a large group of the existing labor force in the coastal urban areas but will necessitate the movement of others into the base areas close to drilling operations. The number of persons needed for each phase of operation will vary and some overlapping of activities will tend to have greater numbers of persons in some of the urban places. As a rule, especially in California as well as much of the Gulf region, the influx of new employees will represent a very small percentage increase into the urban areas, and in many instances where local labor resources are used the impact will be negligible since the persons already reside in the area. The impact will be greater in northern California, Oregon, and Washington because of the absence of large cities along the coast.

Social Impacts

OCS-related development will create impacts on the physical systems, service systems, and business and Government institutions. Population increase is one of the impacts that can be anticipated. Increases of between 20,000 and 145,000 over base projections may be expected in most sample areas excluding Alaska. The low OCS development assumptions require about one-third to one-half this growth. The impacts appear the greatest in the Charleston area, where the population increase could nearly double the current population. Severe impacts, though would occur in Alaska due to as yet untouched, pristine, and fragile ecosystems. Table 84 indicates the impacts on employment and population in several Alaskan communities. Population increases in most regions would be less than 5 percent, except in Florida and Alaska, where the impacts would be larger. For Valdez, Alaska RPA projected a population increase of 45 percent over a baseline estimate in 1985 of eight times existing population. Also some local areas in New Jersey, Jacksonville, and Puget Sound probably would experience a significant growth. The resultant demand for services - for example, schools, hospitals, transportation facilities, residential housing, office space and electric water utilities would require considerable planning and increases in local government expenditures. The ability of a given community to cope with this growth depends on its size, its existing capacity to plan and control growth, and its financial structure. A city where rapid growth has already occurred and planning agencies exist, like Jacksonville, should be more able to respond to OCS-related growth than the smaller communities that are not experienced in meeting the demands of growth.

TABLE 84.

Alaskan Community Impacts

	Valdez	Cordova	Seward	Yakutat
ulation				
1970	1,100	1,600	1,800	250
1985 base case	9,600	3,800	3,300	400
1985 low development	11,500	5,700	5,200	2,300
1985 high development	13,800	8,000	7,500	4,600
2000 base case	25,800	5,600	4,800	600
2000 low development	28,100	7,900	7,100	2,900
2000 high development	29,200	9,000	8,200	4,000
ployment				
1970	325	475	800	100
1985 base case	2,830	1,190	1,160	160
1985 low development	3,190	1,550	1,520	520
1985 high development	3,880	2,240	2,210	1,210
2000 base case	7,200	1,740	2,200	260
2000 low development	7,500	2,040	2,500	560
2000 high development	8,040	2,580	3,040	1,100

ource: Resource Planning Associates, Inc.

There are social and psychological changes as well as structural changes associated with community growth and economic development. Some communities may desire to forego economic gains in order to preserve their traditional life styles and the character of their towns and villages.

The CEQ report presented summaries of the case studies done by RPA which point out several important community impact issues.

> The New England case study shows how development, if not controlled regionally,will gravitate to a number of smaller towns where residential and commercial activity could threaten the architectural and historic resources that have been protected for generations. Development might better be directed to the declining areas of the larger cities, where the infusion of economic activity is needed. The New Jersey analysis shows greatly reduced community impacts by expanding existing sites and locating new facilities in the already industrialized Delaware Valley. The Charleston case study points out the need for locales to anticipate and plan for large population influxes and to protect their most valuable natural and manmade resources from destruction by the new economic forces at work. Good planning and regulatory programs can channel those forces into desirable development that will enhance the environmental quality and life in an area. (CEQ, p. 7-75).

There are important roles for local public officials and planning bodies to plan in planning for and directing the onshore development resulting from OCS activity. In the populous and industrial areas the necessary planning agencies and capabilities probably already exist. Extensive development may also occur, however, in less densely populated or rural areas where there is little or no experience in land-use planning or regulatory activities. Thus, there is a need that the planning capability be developed in such areas prior to OCS-induced development.

2. Summary of Aggregate and Cumulative Impacts of Expanded Program and Comparison with Impacts Under Current Leasing Program

a. On Biological Communities of the Coastal Zone

(1) Beaches and Associated Biota

As mentioned in the description of impacts, beaches derive their value primarily as recreation resources, and as such will be more fully discussed in the following section on recreational and other resources. Beach biota will be severely affected by a spill coming ashore, and the intertidal and shallow littoral benthic biota would also be severely affected. None of the studies on tanker groundings and large spills has indicated that these communities are completely decimated, even by long-lasting spills of higher toxicity, refined products.

(2) Bays and Estuaries

These features are commonly highly productive areas, because of the high level of nutrients brought in by river flow. Many estuaries and bays support shellfish banks and populations; many are also under severe environmental stresses as a result of watershed pollution, industrial activity, and ship traffic. An oil spill entering a bay or estuary would have serious consequences to biological productivity and economic interests in the area, including commercial fishermen. Pipelines would probably not be permittd to cross bays and estuaries with shellfish banks. The impact is generally relegated to the massive oil spill, an unpredictable event in any area. However, increased offshore development increases the risk of such an incident.

Barataria Bay in Louisiana has had extensive oil and gas development for over 25 years. It remains a prime shrimp ground, with no loss of productivity attributable to the hydrocarbon production.

(3) Wetlands

Significant wetland habitat exists in the Louisiana, Texas and Atlantic coast areas. It is difficult to assess the impact that oil and gas production has had on the marshes of Louisiana. Most of the marsh is protected from oil slick penetration. The marshes of Texas are protected by the long stretch of barrier islands extending nearly the length of the State. The most severe impacts are those caused by pipeline and access canals being cut, and dredge spoil banks being created. However, the effects of these activities are difficult to assess because of inadequate baseline information on productivity, circulation and drainage patterns, and wildlife and waterfowl usage. The marshes are currently utilized to a great extent. Perhaps the most crucial unknown is how this development has affected the stocks of those organisms which utilize these areas as breeding and nursery gounds. Again, we can infer from the success of commercial fishing operations in the Gulf of Mexico that reproduction and survival of commercial fisheries has not been severely affected. What is not known is if the maximum sustainable yeilds of the fisheries are being reduced; the fishing effort and current catches are not fully utilizing the resources in the Gulf.

(4) Artificial and Hard Substrate Communities

These communities are found on pilings and jetties and do not represent a significant part of any ecosystem in terms of biomass and energy dynamics. They are mainly affected by oil spills and turbid conditions, as many of them (e.g. barnacles) are filter feeders. It is impossible to predict the effects on these animals of increased leasing, except that these incidents will probably affect them adversely.

(5) Waterfowl

As mentioned elsewhere, waterfowl are perhaps the most conspicuous casualties of oil pollution. Some waterfowl are divers and swimmers, others are dabblers and waders. All can be severely affected by oil spills by coating, and by loss of food sources, nesting and breeding areas by oil spills and pipeline and terminal construction. Inadequate baseline information precludes judgments about the effects on waterfowl in coastal Louisiana and consequently makes predictions of effects in other areas meaningless. Large bird cross bays and estuaries with shellfish banks. The impact is generally relegated to the massive oil spill, an unpredictable event in any area. However, increased offshore development increases the risk of such an incident.

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(6) Wildlife and Sport Fish

The wildlife of Louisiana seems to have been unaffected by the development of offshore oil and gas in the last quarter century. Nutria and muskrat trapping is still a significant industry. Alligator populations are on the increase (they were recently allowed to be hunted after several years of total prohibition). Deer hunting on refuges has had no curtailment in season or limits. The principal impact on wildlife is potential loss of habitat through construction of onshore facilities. This impact is expected to be minimal in areas where sufficient unutilized land is available.

Marine sport fishing can be adversely affected by oil spills. Sport fishermen are not willing to soil their boats and fishing gear with oil, and this would be a depressant to fishing activity in those rare occurrences of large spills. On balance, however, sport fishing activity has been considerably enhanced by offshore oil and gas production, as platforms act as artificial reefs by allowing a surface for settlement of sessile organisms. Eventually a community develops and this food source attracts large schools of sport fish to the vicinity of the platform. The platform thus becomes a prime angler fishing (and spearfishing) area. It is anticipated that this same effect would occur wherever a platform is emplaced. Sport fishing activity and catch would increase in proportion to the number of platforms installed and remaining for some period of time (at least a year).

b. On Recreational, Historical, Archeological, Esthetic, and Conservation Resources

(1) Beach and Shoreline Recreation

Beach and shoreline recreation in any area would not be affected to any great extent from normal offshore operations, no matter how intensive. The transporting of produced hydrocarbons would produce a one-time, short-term impact, i.e. the crossing of a beach by a pipeline. This can be accomplished fairly rapidly by digging a trench and backfilling. The beach rapidly assumes its normal appearance.

The major impacts on beaches and recreation will result from oil spills. Massive oil spills, a rare occurrence for offshore platforms and pipelines, would cause a nearly complete reduction and non-availability of beach activity where they reach the shoreline.

Depending on the amount of oil and length of shoreline affected, clean-up and restoration operations could take a few days to a few months Oil that saturates beaches could remain for many months at some depth in the sand, and may continue to be a problem. Smaller scale polluting incidents contribute small amounts of oil to the much larger amount that comes from other sources such as natural seeps, tanker operations, and ocean oil disposal. These smaller amounts can be manifest as a thin line of weathered oil at the wash line or as tar lumps or balls that wash up onto beaches, an occurrence that causes some distress to beach users both through contact and odors.

Recreational boating will be affected by a large spill in that marinas may receive the oil, but in general, even a large spill does not reduce the available area or time for boating by significantly large spatial-temporal amounts. Bays and harbors may be closed by a spill near the entrance through which boaters would not wish to run their boats.

It is impossible to quantify the possible impact of an unpredictable event such as a major oil spill on beaches and shoreline recreation. Much of the coastlines of California, Texas, Florida, and the Atlantic States are highly used and valued sandy beaches. It is also obvious that the opening of frontier areas to oil drilling introduces the risk of oil spill incidents where no risk existed previously. The cumulative risk will be based on the intensity of development and the particular hazards to operations in each particular region. Operations in the central Gulf of Mexico have been very intensive, and the area is one of generally stable sediments and low seismicity. Most other areas have generally more severe problems to development: North Atlanti- severe weather, icing; California - seismic activity; Alaska - seismic activity, icing and ice rafting, severe weather. Gulf of Mexico beach areas have not sustained a massive spill from offshore operations, and only a combination of unpredictable occurrences resulted in the major incident at Santa Barbara.

(2) Esthetic and Scenic Values

With good visibility, offshore platforms can be seen from the shoreline to a distance of about 17 miles. To many people, this sight represents a degradation of the esthetic and scenic value of shoreline. Other degradations of these values would be caused by oil spills reaching the coasts and siting of onshore terminals. Such values are non-quantifiable, and can be evaluated only by public response to proposals for leasing.

(3) Historical or Archeological Sites or Objects

The unpredictability of oil spill occurrences and drift preclude predictions of the impact on these types objects. The increased possibility of oil spills in frontier areas increases the probability that these objects will be damaged. Historical and archeological sites, on the other hand, would not be severely affected by oil spills, as they are either submerged or upland, rarely occurring at the shoreline.

These sites could be severely damaged by pipeline laying (underwater and on land), terminal and treating facilities construction, and pump station installation. Where these sites are known, these problems can be mitigated by alternative siting. Many of the archeological sites have not been discovered. It has been the practice in the Gulf of Mexico to require surveys around proposed platform sites and pipeline routes to identify these unknown sites and take measures to protect them. These stipulations for archeological surveys in the Gulf of Mexico have recently been strengthened by the Department. Similar surveys would probably be required in any area proposed for leasing. These surveys would be stipulated or sites identified in site-specific impact statements.

(4) Conservation Resources

The risk of adverse impacts to these resources is the same as to the geographic area in general, and increases as the intensity of development increases. These more highly valued resources would have to be identified so that adequate analysis (e.g. matrix analysis of tracts in a proposed sale) and value be attached to them. In many cases, onshore facilities are prohibited from these areas. In such a case, adverse impacts would derive from unpredictable but rare offshore oil spills.

(5) Sport Fishing

Since the only adverse affect on sport fishing that could result from offshore operations is the massive oil spill, we can not quantify this unpredictable impact. Massive spills are not total deterrents to sport fishing; only the area of the spill is removed as fishing area.

The presence of structures offers the one truly positive environmental benefit of offshore activity. The enhancement of sport fishing due to platforms will be in direct proportion to the number of permanent platforms installed within a reasonable cruising distance from shore or harbor facilities. Information from sport fishing effort in the central Gulf of Mexico indicates a large increase in number of man-days spent in this activity. Sport diving and spear fishing is also made available by platforms, often in areas where no suitable or interesting dive spots are available.

(6) Endangered and Threatened Wildlife

Adverse impacts on these organisms would be the same in nature and quantity as to other fauna in particular geographic regions. It is their status of endangered or threatened that makes them highly valued. This statement can not address the possibility or magnitude of adverse impacts to all endangered or threatened wildlife. Identification of habitat and range, as well as life habits and population size information when available, will be made in site-specific impact statements, so that adequate mitigatory measures can be taken to prevent deleterious impact to these species.

c. Land Use and Socioeconomic Effects on Onshore Development

General quantification of the effects is found in the preceeding section (III.C.1.c.) on the description of these effects.

D. Impact on Air and Water Quality

1. Description of Impacts

a. Air Quality

The quality of air in any area could be degraded by exhaust emissions of stationary power units and service vessels, and by the accidental release of oil and gas from wild wells.

The impact of exhaust emissions is unknown, but considering the small total horsepower requirements it is thought to be small.

The average composition of natural gas as delivered to pipelines in the United States is:

Methane	CH_4	72.3%
Ethane	C_2H_6	14.4%
Carbon dioxide	CO_2	0.5%
Nitrogen	N_2	12.8%

(Small amounts of sulphur and other materials could also be present in some localities) (source: Ley, 1935)

If a wild well were not burning, obviously, the above gases would simply be released into the air. If the gas well was on fire, combustion would be essentially complete and the emissions would consist almost entirely of carbon dioxide (CO_2) and water; the nitrogen would remain as N_2 and any sulfurous gases would be oxidized to SO_2. The resulting impact would not be great.

If a wild well were releasing crude oil into the water, the resulting impact would be substantially greater. If the oil does not burn, a significant amount of it will evaporate. During the Chevron, 1970 spill it was estimated that 15% of the roughly 30,000 bbl. spilled evaporated. At an average density of 310 lb./bbl., this incident would have introduced almost 14,000 lb. of hydrocarbons into the air. Some oil spills in the past have resulted in fires.

A reasonable estimate of the range of emissions, assuming complete combustion, that an oil well fire could produce per 1,000 bbl. burned, might be as follows: 1/

CO_2 : 340,000-347,000 lb.
SO_2 : 620-34,000 lb. 2/
NO : 660-10,000 lb.

(As a point of reference, during the Chevron - 1970 fire and spill, the maximum spillage rate was estimated to be 1,000 bbl. per day.)

Combustion of oil would in reality be incomplete, however, and emission would contain somewhat less of the above compounds, but would include, in addition, such materials as volatilized petroleum, particulate carbon, carbon monoxide, nitrous oxide, sulphur monoxide, along with other altered or partially oxidized matter. There is no reliable way to predict in advance the relative volumes of each of

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1/ Values used in calculation are based on world averages for crude oil of 310 lb/bbl.; Percent content by weight is: carbon 82.2 to 97.1, sulfur 0.1 to 5.5, nitrogen 0.1 to 1.5 (Levorsen, 1958).

2/ SO_2 emission would be less for Gulf of Mexico crudes, which range from 0.1 to 0.5% sulfur.

these possible emissions because it would depend, among other things, upon moisture content of the air, wind speed, pattern of oil spray from wild wells, number of wells involved, chemical content and physical character of the oil itself, and types of equipment and materials other than oil that might also burn.

As previously discussed, an increase in refinery capacity will add to the total emissions of oxides of nitrogen, sulphur dioxide, hydrocarbons, carbon monoxide, and hydrogen sulfide, particularly to the atmosphere. An increase in refinery capacity and other petrochemical industries to process all the increased production resulting from this proposal would cause a substantial increase in emissions. Oil produced as a result of this proposal, however, may not necessarily create the need for increased refinery capacity and other petrochemical industries; it may replace oil that otherwise would be imported or it may take the place of oil that will not be furnished from domestic sources due to declining production or other factors.

b. Water Quality

The natural condition of sea water may be altered and degraded in several ways during oil and gas operations.

Debris and bilge will be released into Gulf waters from the many seismic vessels, crew boats, tugs, and service and supply boats used throughout operations. No estimate can be made of the quantities involved.

During drilling operations, drilling fluids and drill cuttings will be discharged into the sea. Most drill cuttings in the Gulf consist of sand and shales and therefore cause no turbidity, but settle to the bottom quite rapidly, on the order of minutes. The drill cuttings are washed prior to disposal.

It has been estimated that 1,700 barrels of cuttings and as much as 300 tons of turbidity-producing mud compounds are discharged overboard during the course of drilling an average 10,000 foot well.

Three components or properties of formation waters contribute to water quality degradation when released into the sea. One is the small amount of entrained liquid hydrocarbon. There are some locations disposing of formation water where the treatement equipment puts out an effluent with less than 25 ppm oil content; control is not being accomplished across the board on a continuing basis. Many other locations only manage to meet the requirements of OCS Order No. 8, releasing waters with entrained oil averaging less than 50 ppm. The second property of formation water that degrades water quality is its high concentration of dissolved mineral salts. This value ranged from 61,552 mg/1 to 270,000 mg/1 in 76 samples from the OCS off Louisiana. This contrasts sharply to the average sea water salinity of 35,000 mg/l. The third degrading property results from the fact that formation waters are devoid of dissolved oxygen. Current production of formation waters from all Louisiana OCS operations is 605,000 bbl./day; 305,000 bbl./day is transported to shore.

Water quality could be further degraded as the result of accidental oil spills, but the degree of degradation is impossible to predict. Part of this spilled oil would be removed by clean-up operation and some would evaporate, but the largest proportion would probably be dispersed into the ocean waters.

Another source of water quality degradation is the resuspension of sediment during pipeline construction and burial. The jetting away of the substrate from beneath the pipeline will result in creating a plume of trubidity trailing away from the operations in the direction of the current. The plume can reach proportions of several yards wide and hundreds of yards long if the substrate is exceptionally muddy. The duration appears to be on the order of several hours at a given location.

Water quality in some areas of Louisiana is affected by effluents from oil refineries and petrochemical plants. Although production from this proposal will probably not require an expansion of refinery capacity nation-wide, it will be refined in the area along with production from other non-OCS sources. In this manner, production from this proposal will contribute to the continuation of refining activity in various regions and its resultant effects on water quality. Effluent discharges could increase the total dissolved solids, oil, and biological oxygen demand; these discharges, however, must meet existing local, State, and Federal anti-pollution standards.

2. Summary of Aggregate and Cumulative Impacts of Expanded Program and Comparison with Impacts Under Current Leasing Program

The aggregate and cumulative impacts on air and water quality that will result from the 10 million acre proposal are impossible to determine. Extensive baseline data must be accumulated from the literature and field and follow-up monitoring studies conducted, as the Gulf of Mexico can provide little baseline data. Gulf of Mexico air and water quality impacts are discussed in the previous section.

E. Impact on Commercial Fisheries

Offshore oil and gas operations interfere with commercial fisheries in two general ways: they may affect changes in the biology of the organisms, and they may effect changes in the socio-economic aspects of fishing operations. To a large extent these two ways of interference are independent, and will be discussed individually. Both ways of interference have the same ultimate effect, namely the reduction of the potential catch.

1. Impact on Commercial Fish and Shellfish

Biological impact occurs primarily as a result of oil spills. The degree of biological damage from spills depends on a number of factors, including the type of oil spilled, the amount of oil spilled, the biota of the area, the season, weather conditions, previous oil exposure, treatment of the spill, and others (Hay, 1974). Fish and shellfish can be killed directly by coating and asphyxiation, poisoning by contact, and poisoning from water-soluble fractions. Examples of these types of kills are given by Nelson - Smith (1973). The author suggested that adult fish can probably keep clear of oil, except those living in enclosed waters. However, Hampson and Saunders (1969) reported many adult fish killed near Woods Hole, Massachusetts after a local oil spill. Shellfish, such as clams and oysters, are more vulnerable due to their sedentary mode of life in shallow water.

Oil spills may also destroy the eggs, larvae and juveniles of fish and shellfish. Many fish and shellfish have floating eggs and larvae which are vulnerable to oil spilled onto the surface. Hester (1974) concluded that such an impact would be local, except for certain critical periods of the year. Hester noted that oil contact with the shore during particular stages of the tide could possibly destroy a year class of clams or the grunion fish.

Oil spills may also destroy the food sources of fish and shellfish. Plankton is the basic food source for many smaller commercial fish (herring, menhaden, etc.). Although Galtsoff, et al. (1935) reported that low levels of crude oil apparently stimulated phytoplankton growth, Nelson - Smith (1973) summarized many studies which show the lethality of crude and refined oil on both zooplankton and phytoplankton populations. The specific effect of oil spills on plankton is not clear, particularly in field observations. Straughan and Abbott (1971) suggested that the rapid rate of plankton production obscures any local or temporary reductions due to oil spills.

Oil pollution from any source may introduce carcinogenic (cancer-causing) hydrocarbons into the aquatic environment, which may in turn be concentrated within the bodies of commercial fish and shellfish. Hester (1973) reviewed several studies which indicated oysters and clams could become so contaminated with carcinogenic hydrocarbons to be unfit for human consumption. The direct biological effect of these compounds on the organisms is unknown.

Petroleum products discharged into the waters may affect the behavior of organisms. The behavioral changes may involve a reduction of the organism's ability to survive due to alterations of the nervous system, or the changes may be avoidance reactions to the oil. The latter behavior may have significant impact on anadromous fish species which concentrate at river mouths and then migrate upstream to spawn. A major spill at the mouth of a river used for spawning may cause returning fish to refrain from moving upstream to spawn for a portion or all of the spawning season.

In summary, oil spills present the greatest potential hazard to commercial fish and shellfish. Fish kills have been documented in several areas of major spills of refined oil.

Impact will be greatest on commercial species which are concentrated within enclosed bodies of water. Shellfish, such as oysters, clams, and aquaculture species held in nearshore waters or in estuaries (such as salmon fry) are vulnerable. Mobile species living offshore are considerably less vulnerable as these species can avoid the spills. Impact on bottom-living species (lobsters, shrimp, crabs) may occur if oil spills sink to the bottom, but unless the spill is massive, the impact will be very localized.

2. Impact (socio-economic) on Commercial Fisheries

Offshore oil and gas operations interfere with commercial fishing activities in several general ways.

a. Removal of the Sea Floor From Use

Those fisheries involved with exploitation of bottom or demersal species are impacted by the removal of fishing grounds. All sites occupied by drilling or production platforms, as well as attendant service boats and barges must be avoided by fishing boats. Fisheries involved include shrimp (the most valuable fishery in the U. S.), lobsters, Pacific coast crabs, and bottom fish (flounders, halibut, industrial groundfish). Jack-up drilling rigs or permanent production platforms effectively remove two to five acres of fishing are per structure. In deeper waters (over 100 meters), a semi-submersible drilling rig with a 300 meter anchoring radius would remove up to 325 acres. The duration of the exploratory drilling ranges from about 45 days for a single well to around six months for multiple well explorations. Permanent production platforms may remain in place for 10 to over 20 years.

Structures placed on the sea floor are known to attract large numbers of fish in the Gulf of Mexico and California. (There is no evidence that these new populations are made up of displaced individuals from nearby populations.) Commercial and sport fishermen work around these rigs because of the large populations of fish commonly found there.

The total number of platforms required to develop a lease area and their spacing relative to each other are important factors in considering potential impact on commercial fishing activities. In addition to the removal of the sea floor for fishing, the structures and additional traffic increase the congestion within an area, requiring fishermen to spend more time navigating and avoiding collisions.

b. Creation of Obstructions

Offshore oil and gas operations create obstructions on the sea floor, such as underwater stubs, large pieces of debris, and buried pipelines. Underwater stubs present a hazard to trawlers (shrimp, bottom-fish) in that if the net is towed across a stub, the net will certainly be badly damaged or lost.

Large pieces of debris, such as equipment, piping, structural members, tools, etc., may accidentally be lost off a platform, service boat or barge. If these pieces are not recovered, they may cause damage or destruction of nets or other fishing gear which encounter them.

Unburied pipelines (beyond the 200 foot depth contour) may pose a problem to bottom trawl fishermen. However, about 90% of the Gulf of Mexico shrimp catch was harvested inside the 120 foot depth contour. Pacific coast shrimping grounds are generally in areas of low petroleum potential (northern California, Oregon). California trawling fishermen have indicated unburied pipelines may pose some problems, but felt they could maneuver their vessels so as to minimize damage or loss of their nets (U. S. Geological Survey, 1974). Pipeline corridors and pipeline burial out to the 200 foot depth interval within a lease area reduces the hazard, although this is not required of all pipelines shallower than 200 feet.

c. Contamination of Fish by Spilled Oil

Fish which are either externally coated or internally contaminated with oil are unmarketable. It has been shown that organisms living in the vicinity of chronic oil spillage are likely to be internally contaminated (Connel, 1971; Scarratt, 1971). The extent of contamination in offshore waters is not detectable, but is so in some coastal areas where water-borne or water-soluble petroleum products can become concentrated.

A secondary impact of oil contamination of fish and shellfish is that the marketability of these fishery products is initially reduced due to the direct health or esthetic effect of the oil. The fishery product may gain a poor reputation and the economic effect may far outlast the period for which the fish are actually tainted.

d. Reduction of Fishing Effort Due to Spilled Oil

Oil spills may reduce fishing effort, which in turn reduces the total catch. Effort reduction occurs when oil actually fouls fishing nets and gear, or the presence of oil in the water restricts fishermen from fishing for fear of fouling their gear. Straughan (1971) indicated that landings of rockfish were greatly reduced in the Santa Barbara area because of a reduction of fishing effort caused by oil contamination of boats and gear, as well as the negative esthetic appeal of fishing in polluted waters.

Areas of chronic oil pollution may also foul fishing gear on occasion, resulting in extra expense and reduced fishing effort while cleaning or replacing the gear. This may be significant where large purse seines are used at the surface (such as for Alaska salmon).

(e) Removal of Onshore Sites Considered for Aquaculture

Aquaculture of marine organisms, such as clams, oysters, and juvenile salmon is emerging as an industry. Pollution effects can be severe on this industry. Clark and Finley (1971) stated that a single large oil spill in Puget Sound could destroy the area's extensive aquaculture industry. These authors noted that the State of Washington denied oil and gas lease applications in Puget Sound. The state considered such action incompatible with a potential multi-million dollar a year seafood cultination industry.

Future seafood aquaculture industries may refrain from establishing operations in areas associated with petroleum products if a pollution potential exists.

3. Summary of Aggregate and Cumulative Impacts of Expanded Program Comparison with Impacts Under Current Leasing Program

a. On Commercial Fish and Shellfish

It is impossible to quantify the effects of this proposed program, or even the present program, on the organisms themselves. Information is available on pollution problems which reduce the marketability of shellfish, but the pollution sources are often difficult to determine. Whole oyster reefs may be contaminated, but community viability remains, so that the only loss is the current crop. The whole question might be addressed from the standpoint of how offshore operations affect the maximum sustainable yeilds of commercial fisheries, but this is an extremely complex problem. (See concluding paragraph of section b. that follows).

b. On the Socio-Economic Aspects of Commercial Fisheries

The amount of seafloor that is removed from use by fishing trawlers will be directly proportional to the number of platforms installed, assuming an average cover for a platform. The impact in any area will also depend on the size of a sale, the amount of acreage leased, and the hydrocarbon potential or discoveries. This proposal may result in up to 1600 new platforms being installed on the U.S. OCS; this would constitute a removal of approximately 8000 acres of seafloor from fishing activities.

Obstructions on the seafloor would also be roughly proportional in number to the intensity of development of a given area. The magnitude of this problem is difficult to assess. Fishermen generally do not report such incidents (number or location); if they can identify the cause of the loss (e.g., a stub) and the owner, they go directly to that group for compensation.

The magnitude of the problem of reduced fishing effort due to spilled oil of any amount is also difficult, if not impossible, to assess, even in the Gulf of Mexico.

All of the problems cited above have been experienced by commercial fishermen in the Gulf of Mexico. However, the end results, total catch and catch per effort, seem not to have been adversely affected by offshore operations over the last 25 years (see Resources section for Gulf of Mexico). Indeed, total catch and catch per effort for most species has increased in this period. Aside from the occasional net snaggings for which they are compensated, commercial fishermen state that they have little problem working in the area. The congregation of fish near rigs aids fishing effort to some degree.

F. Impact on Ship Traffic and Navigation

1. Description of Impacts

a. Ship Traffic

In the Gulf of Mexico safety fairways have been established for the safe passage of vessels enroute to, or from U. S. ports. Consequently, placements of rigs or platforms are prohibited within these fairways. Ships do not always use these fairways and this increases the possibility of a collision with drilling rigs, permanent platforms or vessels attending these platforms. Impacts which could result include loss of human life, spill of oil, release of debris including part of, or the entire drilling rigs, and the ship, if it sinks. The contents of the ship's cargo could pose a serious threat to the environment if it includes toxic materials such as chemicals, crude oil, or refinery products. Statistics on ship-platform collisions are given in Tables 85 and 86 .

A marine casualty is any casualty involving a vessel other than a public vessel if such casualty occurs upon the navigable waters of the United States, its territories or possessions, or any casualty involving a United States vessel wherever the casualty may occur. Casualties involving commercial vessels are required to be reported to the Coast Guar whenever the casualty results in any of the following: (a) actual physi l damage to property in excess of $1,500; (b) material damage affecting the seaworthiness or efficiency of a vessel; (c) stranding or grounding; (d) loss of life; or (e) injury causing any person to remain incapacitated for a period in excess of 72 hours;

TABLE 85. MAJOR COLLISIONS WITH LARGE OFFSHORE STRUCTURES, FY 63-73

NAME	TYPE	DATE/TIME/INCIDENT/CAUSE	WEATHER CONDITIONS
GANGES (British)	Cargo	9 Nov 63, night - Collision in Gulf of Mexico - $5,000 damage.	Overcast, visibility over 2 miles, wind 30 lts. seas ;5=2- ft/
PHILLIPS PLATFORM 115-3	Fixed Structure	$300,000 Damage CAUSE - PERSONNEL FAULT	
DAUPHIN (O.N. 254298)	Towboat	4 May 64, day - Collision in Gulf of Mexico.	Partly cloudy, visibility over 2 miles, wind 20 kts, seas 5 ft.
AIPLE #50 (O.N. 276123)	Cargo barge		
UNKNOWN	Fixed Structure	CAUSE - PERSONNEL FAULT $180,000 Damage	
GENERAL ARTIGAS (Argentine)	Cargo	15 Dec 65, day - Collision in Gulf of Mexico.	Unknown
SHELL-PHILLIPS FEDERAL BLOCK 135		CAUSE UNDETERMINED $200,000 Damage	
SUPERIOR 103-1	Fixed Structure	12 Sep 67, 2130 - Damaged by Collision with unidentified vessel. L29°16'16.74"N 92°22'13.1"W $100,000 Damage	Unknown
M/S EMMA JOHANNA (German)	Cargo	30 Oct 67, 0130 - Collision in Gulf of Mexico. L28°29'36.158"N 90°51'25.54"W	Heavy rain, poor visibility wind SE 45 kts, seas SE 15-20 ft.
KERR McGEE OIL PLATFORM OCS	Fixed Structure	$12,000 Damage CAUSE - PERSONNEL FAULT $1,100,000 Damage	
M/V OLYMPIC FLAME (Liberian)	Tankship	10 Oct 70, 2200 - Collision in Gulf of Mexico. $60,000 Damage L28°41'17"N 91°46'20"W	Clear, visibility 5 mi., wind E 7 kts, slight sea.
PLACID OIL CO. PLATFORM 202-1	Fixed Structure	$865,000 Damage CAUSE - PERSONNEL FAULT	
KIMON		4 OCT 65 - Collision in Gulf of Mexico	Unknown
CONTINENTAL OIL PLATFORM D - BLOCK 47	Fixed Structure	CAUSE UNKNOWN	
ESSEX	Cargo	27 AUG 69, 2340 - Collision in Gulf of Mexico- $10,000	Overcast, visibility 18 miles, wind S 5 LTS gusting, moderate sea slight swell (SE-2 ft.)
HUMBLE OIL OFFSHORE STRUCTURE #142-2	Fixed Structure	L29° 06' 19" N 94° 23' 47" W $500,000 Damage CAUSE - PERSONNEL FAULT	

TABLE 86. COLLISIONS WITH OFFSHORE STRUCTURES
FY 63-73 (Vessels less than 1000 G.T.)

Vessel Type	Total Number	CAUSE				TOTAL DAMAGE (Thousands of Dollars)		# of People Injured
		Adverse Weather	Personnel Fault	Equipment Failure	Fault of Rig	Vessel	Rig	
A. Fishing Vessel	10		5	1	4 [a]	151 [e]	24	1
B. Barge	2	1		1		35	68	0
C. Small Cargo Vessel	8	3	4		1[b]	221[d]	10	2
D. Passenger Vessel	2			1	1[c]	19	0	1

Dates of Accidents

A.1. Feb. 66
2. June 66
3. May 67
4. June 67
5. Oct. 67
6. Nov. 67
7. May 70
8. June 70
9. Nov. 71
10. Dec. 71

B.1. Dec. 65
2. Dec. 65

C.1. Dec. 65
2. Dec. 66
3. July 67
4. May 70
5. July 71
6. Sept. 71
7. Sept. 71
8. Nov. 71

D.1. Feb. 70
2. Feb. 70

[a] Three equipment failures, 1 insufficient/improper lighting

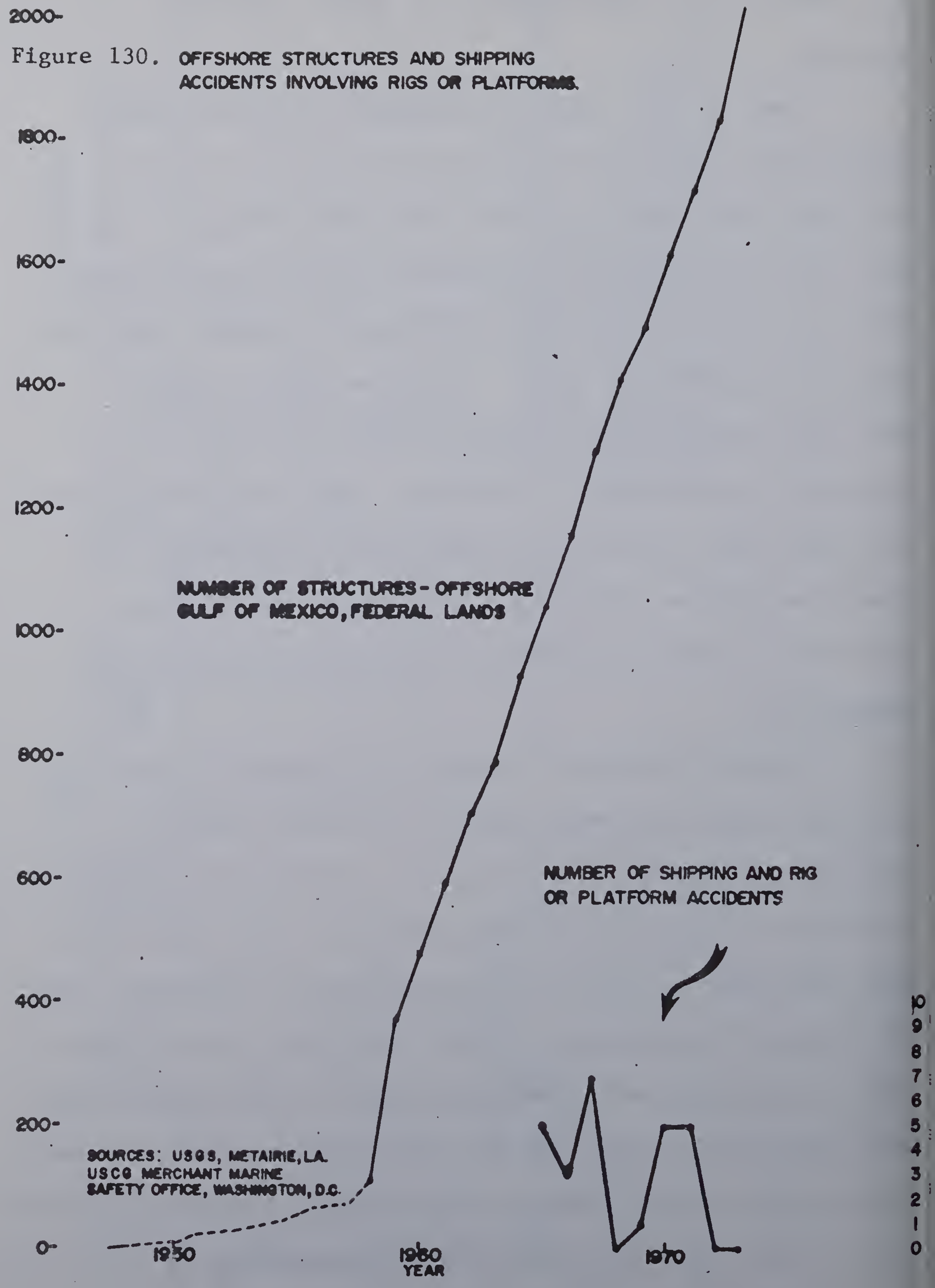
[b] Improper maintenance
[c] Insufficient/improper lighting
[d] Includes $130,000 to one vessel
[e] Include 80,000 to one vessel that sunk

except injury to harbor workers not resulting in death and not resulting from vessel casualty or vessel equipment casualty.

Table 85 is a summary of reported collisions between large vessels and offshore structures in the Gulf of Mexico. The eight cases cover the period 1 July 1962 through 30 June 1973 and include only those collisions involving vessels over 1000 gross tons. When location is known, the latitude and longitude of the platform is given. Twenty-two other collisions with fixed structures were reported during this eleven year period and are summarized in Table 86 . Fifteen accidents involving vessels less than 100 gross tons and the remaining seven vessels were between 100 and 650 gross tons. In all cases, there was no loss of life involved and damage to the rig was insignificant.

Figure 130 shows the increase in the number of offshore structures versus the small number of accidents involving these platforms in the Gulf of Mexico. It should be noted that the number of accidents involving structures is not increasing while the number of structures is increasing at a phenomenal rate. The accidents involving small vessels (Table 86.) might in some cases be considered self-generating; that is, the fishing vessels could have been near the rigs due to the improved fishing around the structures and the barges, cargo vessels and passenger vessels could in some cases have been servicing the platforms.

Figure 130. OFFSHORE STRUCTURES AND SHIPPING ACCIDENTS INVOLVING RIGS OR PLATFORMS.



SOURCES: USGS, METAIRIE, LA.
USCG MERCHANT MARINE SAFETY OFFICE, WASHINGTON, D.C.

The most serious environmental hazard involving offshore structures and shipping accidents would occur in the case of an oil tanker ramming a platform. In this theoretical case supertankers might be considered in a more favorable light than small tankers if the following were the case:

1. The offshore terminal buoy process was used. These are know as offshore deepwater terminals or "Superports". One terminal is planned for offshore Freeport-Galveston and another is planned for offshore Corpus Christi
2. The fairway, the area near the fairway, and the area around the terminal buoy had no nearby bathymetric hazards, or these hazards were carefully surveyed and marked.
3. The supertankers were kept in the fairways in the area of offshore structures.
4. The supertanker traffic was restricted to one way traffic in the fairways so tankers were never on head-on courses.

Supertankers and deep water buoyed terminals would decrease the traffic created by the small tankers presently in use. The fewer number of tankers and the higher care in the moving of supertankers would appear to decrease the probability of tanker-platform related accidents.

(2) Navigation

Very little interference can be expected between drilling rigs and platforms and ships that are utilizing established fairways. However, at night, and especially during rough weather, fog, and heavy seas, ships not navigating the fairways could collide with fixed structures. Also fishing boats engaged in trawling will be inconvenienced by having to navigate around fixed structures located on fishing grounds. Based on U. S. Geological Survey estimates, 150-250 new platforms could result from one million acres of additional leases. Approximately 2,000 platforms are now in the Gulf of Mexico. Increasing the number of platforms represents a potential increase in possible interference with shipping.

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G. Impact on Military Use of the OCS

The U.S. OCS and continental slopes are used rather extensively by the Navy and Air Force for training and research operations. Current activities include missle testing, ordnance testing, drone recovery operations, and electronic counter measure (ECM) activities by the Air Force. Mine research is conducted by the Navy. Most of this activity takes place in areas designated for these purposes. Undesignated secret activities also take place in some areas. Rather than issuing blanket restrictions on development in certain areas, the Department of Defense reviews tract lists and selection for proposed sales, and indicates restricted areas before the tract lists are finally developed.

H. Impact on Mineral Resources

The impact on mineral resources of extraction is treated as an irreversible and irretrievable commitment of resources (see section VII). The effect of development to date and that which is proposed by this program is that the high quality fields and easily recovered resources have been or will be exploited first. This is an obvious economic and Federal policy fact. The delay caused by such "high-grading" in developing effective technologies of secondary and tertiary recovery, which will eventually have to be used to extract OSC oil and gas, is one that warrants some serious planning.

I. Impact on OCS Oil and Gas Resource Management and Supervision System

1. Impact of Proposed Action on Existing Level of Environmental Study Prior to Leasing

Environmental studies had been planned for all OCS areas before the announcement in January, 1974 of the proposed increase in acreage to be leased. Section I. D. 5. a. describes the various literature and field studies either recently completed, ongoing, or requested in the FY'75 budget. Existing environmental and socio-economic information reports are currently being completed for the Atlantic coast, the Southern California Borderland, and the Gulf of Alaska. These studies will be used in the environmental analyses conducted for site-specific impact statements in areas where lease sales are proposed.

The leasing of the frontier area of Mississippi, Alabama, and Florida committed the Department ot an environmental baseline and monitoring program in that area (described in section I. D. 5. c.). This decision also carried with it a commitment to initiate baseline environmental studies in other areas (specifically the Gulf of Alaska and South Texas after MAFLA). Planning has already begun with the two agencies in charge of the field program, NOAA (Gulf of Alaska) and USGS (South Texas). Other OCS areas will have baseline and monitoring studies; these will be initiated when areas are designated for leasing in a long-range plan so that the studies can have maximum lead time before sales, and when funding and manpower becomes available.

The only effect that the accelerated schedule has on the environmental baseline program is that, in order to satisfy the 10 million acre requirement, frontier areas must be opened. The designation by the Secretary of the scheduled frontier areas to be opened will determine the studies schedule. Baseline studies must precede leasing for validity.

2. Impact of Proposed Action on Existing Level of Supervision of Development Operations

In FY 1973, the USGS had 37 inspectors who conducted the inspections of OCS operations in the Gulf of Mexico. In FY 1974, there were 49 inspectors for the same purpose. The USGS, in response to the President's call for accelerated leasing in 1975, has made a line item request for 25 additional inspectors in the FY 1975 budget (10 of which will go to the Western Region OCS) and anticipate a FY 1976 budget request for 25 more inspectors. This will result in an inspection force at the end of Fiscal Year 1976 of

	Gulf of Mexico	Western Region	Other Areas
Inspectors	100	16	10
Support	49	13	10

The USGS has indicated that its responsibility for supervision of operations can be fulfilled to the present degree of completeness by this number of personnel, at least in the early development stages. The present degree is the minimum to be expected; it would as the extent of development be desirable to continue to tighten inspection.

(intensity and geographical area) can not be determined precisely at this time, it is difficult to predict future needs. However, full-scale development of ten million acres offered in 1975 will not occur for at least three to five years; inspection personnel levels can be adjusted upward in future budgets in response to perceived staffing needs. Inspector training programs will have to be upgraded both to handle the increased personnel and to prepare inspectors for the specialized operating conditions in unique physical conditions such as found in Alaskan waters.

Within BLM, the expansion into frontier areas was planned in the 5-year schedule of provisional leasing issued in July 1973. The Bureau opened field offices in these areas in the last half of 1973, specifically in Los Angeles, New York, and Anchorage (the other office in New Orleans has been there for several years). Staffing has proceed in a timely fashion, but BLM has responsibilities in the management of OCS leasing, not supervision, and manpower requirements are not as critically tied to the level of leasing as is USGS with supervisory responsibilities.

IV. MITIGATING MEASURES INCLUDED IN THE PROPOSED ACTION

A. General Mitigating Measures

It is not the intent or scope of this document to identify all those aspects of oil and gas operations in particular geographic areas that might require mitigating measures. Some of the standard aspects of operations and how they are mitigated are discussed in the succeeding section. It is the intent here to state the mechanisms and authorities for employing various mitigating measures.

Regulations governing OCS oil and gas lease operations in the Gulf of Mexico are contained in Title 30, Code of Federal Regulations and OCS Orders Nos. 1-4, 6, 7, dated August 28, 1969, No. 5, dated June 5, 1972, Nos. 8-9, dated October 20, 1970, No. 11, dated April 5, 1972, and No. 12, dated August 13, 1971. (See Attachment A). Leasing regulations are contained in Title 43, Code of Federal Regulations. The regulations established procedures and requirements to be followed in all stages of lease operations: exploration and development, drilling, production, transportation (pipeline construction and operation) and abandonment.

The OCS Operating Orders were established under the authority ultimately of the OCS Lands Act, and more directly from the regulations just cited. There are Operating Orders for both the Gulf (12) and Pacific (10) coasts (see Attachment C). These orders specify operating conditions and procedures in more detail than the regulations, and address conditions and problems in the specific geographic areas, although there is overlap on procedural matters such as oil spill reporting format. Operating orders will also be developed for the Alaska OCS and Atlantic OCS, should these areas be opened to leasing as a result of this (or some other) proposal.

The development of operating orders in these areas must precede the offering of tracts for oil and gas development. Operating regulations, on the other hand, apply to all OCS oil and gas operations, not just to those presently occurring. These regulations and orders are discussed in more detail in section I.D.2.

B. Mitigating Measures Related to Specific Phases and Components of Operations Under Proposed Action

1. Geophysical Exploration

Operating plans must be submitted to and approved by the U. S. Geological Survey (GS) before geophysical exploration can be initiated. The resulting permit to conduct the survey will contain any applicable constraints and stipulations necessary to mitigate any possible adverse impacts. With the advent of the new energy sources (sparkers, air guns, gas guns etc.) the last of the truly destructive part of geophysical exploration - the detonation of explosives in the water - has been eliminated.

2. Exploration Drilling

a. Shallow Water

Operating plans, including casing and mud programs, for all (Development as well as exploratory - shallow and deep) drilling on the U. S. OCS must be approved by GS. These plans also detail all equipment to be used such as blowout preventors, automatic drilling controls, mud condition and volume sensers.

Thus, the drilling permit - and subsequent inspections to insure compliance - in the first line of defense against lost well control.

Other measures such as marking and lighting of structures and pollution and waste disposal are covered, in the Gulf of Mexico

OCS by the OCS Orders issued by the OCS Supervisor and approved by the Chief Conservation Division GS.

Special situations can be dealt with either on a lease or well-by-well basis by attaching specific stipulations to the lease or drilling permit.

During the courseof drilling all operations are inspected at least one time. A complete drilling inspection is normally conducted on each drilling rig approximately every six weeks. Random inspections may be made more frequently.

b. Deep Water

All of the general mitigating measures mentioned in the preceeding section apply here as well. In water depths beyond the range of jack-up rigs (approx. 350 ft.), the riser connecting the floating rig to the sea floor, while held in tension, must have some flexibility to allow for movement of the floating drilling platforms and thus is more vulnerable to failure than the rigid risers used on bottom founded rigs. However blow out preventors have been developed and tested that are mounted on the sea floor between the well head and the riser. These BOP's can now operate in 2100 feet of water with a reaction time of less than 10 seconds.

3. Field Development

a. Platforms

The design and installation of drilling and production platforms on the U. S. OCS will be covered by OCS Orders issued by the area OCS Supervisor and approved by the Chief, Conservation Division G.S. Platforms, generally will not be allowed in shipping fairways and the total number of structures per tract will be limited as much as possible.

b. Drilling

All of the mitigating measures described for Exploratory drilling apply equally to Development drilling. In the case of development drilling on a multi-well platform, extra precautionary measures may be required due to the proximity of the drilling in progress with completed producing wells.

c. Completions

(1) Platform

The requirements for completion of development wells will be covered by OCS Orders issued by the Area Supervisor and approved by Chief, Conservation Division, Geological Survey. These orders will specify the type of subsurface safety devices required, the type and number of well head valves required, equipment testing intervals, procedure and reports to be submitted. In general, these orders will specify surface- or remote-controlled subsurface safety valves, fail-close tubing head valves, redundant tubing head valves in some cases, access to the annulus between all casing strings and periodic testing with concurrent reporting for all safety devices.

Produced formation water as well as sewage must be treated to comply with the Federal Water Pollution Control Act before it can be discharged into the sea. In the Gulf of Mexico OCS Order No. 8 is in the process of being revised to require all producing wells to be shut-in while drilling or workover operations are in progress.

(2) Subsea

In addition to the mitigating measures described in the preceeding section on platform completions, subsea completions would remove the obstructions (platform) from the surface of the water and thus reduce the danger to ship traffic.

d. Production Facilities

(1) Platform

The requirements for constructing and operating producing facilities on the OCS will be included in OCS Orders issued by the Area Supervisor and approved by Chief, Conservation Division, Geological Survey. These Orders will require safety devices such as high-low pressure shut-in controls, high-low liquid level shut-in controls, pressure relief valves, automatic fire fighting systems, as well as gas, flame and smoke detectors to trigger alarms. Finally the entire platform is provided with drip pans, gutters and sump to prevent the discharge of any oil into the sea.

(2) Subsea

Subsea production facilities are still in an early stage of development. Because of their planned location on the sea floor, and thus infinitly more inaccessible than a platform located facility, it would appear axiomatic that the developer, from a purely economic standpoint would devise the safest, most reliable and long-lasting facility possible.

4. Transportation of Oil and Gas

a. Pipelines

The potential impacts of each specific nearshore and coastal pipeline construction project are considered by the Department in its review of Corps of Engineers permit applications.

The Department will conduct an environmental analysis on any application for a pipeline right-of-way that is receives. If it is determined that a pipeline right-of-way will have a major impact on the marine or coastal environment then an environmental statement will be prepared.

The adverse effects associated with pipeline installation can be substantially reduced with adequate planning and by using the most appropriate construction techniques. For example, pipeline corridors or existing pipeline canals can be used whenever possible so that adverse impacts are restricted to fewer locations.

Agencies having responsibility or jurisdiction over all or parts of oil and gas pipeline installation or operation in coastal areas are: (1) Department of the Interior, (a) Bureau of Land Management--rights-of-way for common carrier pipelines on the OCS, (b) Geological Survey--jurisdiction over producer owned gathering lines and flowlines on the OCS, (c) U.S. Fish and Wildlife Service--protection of fish and wildlife resources and their habitat through consultation with the Corps of Engineers in the process of issuing Federal permits in navigable waters; (2) U.S. Army Corps of Engineers--issues permits for construction (including pipelines) on OCS and in other navigable waters; (3) Federal Power Commission--grants certificates of convenience and necessity prior to construction of interstate natural gas pipelines; (4) Interstate Commerce Commission--grants approval of the tariff rates for transportation of oil by common-carrier pipelines; (5) Department of Transportation, Office of Pipeline Safety--establishes standards for pipeline construction, operation and maintenance; and (6) Department of Commerce, National

Oceanic and Atmospheric Administration, National Marine Fisheries Service--protection of marine fishery resources and their habitat through consultation with the Corps of Engineers in the process of issuing Federal permits in navigable waters.

The Bureau of Land Management has initiated a study to investigate the extent and character of damage to coastal resources from pipeline construction. The study, will attempt to develop criteria for pipeline system planning for application in OCS areas which have not been subjected to extensive mineral development. High priority will be given to developing criteria for the protection of bottom and shoreline resources in this study. In addition, an interagency study is being initiated to explore the feasibility of pipeline corridors on the OCS and in coastal marshes. Private industry has initiated a study of pipeline effects in marsh areas.

b. Tankers and Barges

The use of tankers and barges to transport oil on the U.S. OCS will be severely limited to the collection of oil from well tests prior to pipeline installation. All tankers and barges used to move oil from the OCS to the U.S. mainland must be U.S. flag vessels and certification requirements are administered by the Coast Guard.

5. Offshore Oil Storage

Offshore oil storage is limited to the relatively small volumes maintained on producing platforms. Tanks are usually small (up to 10,000 bbls.) and well equipped with pressure release valves and high liquid level sensors and alarms.

6. Onshore Treating and Storage Facilities

The onshore terminals that receive crude oil from the U.S. are, of course, subject to the regulating agencies of the State in which they are located. Should the effluents from oil/water separation processes or other waste products be discharged into navigable waters, they must meet the requirements of the Federal Water Pollution Control Act.

Crude oil storage tanks are individually surrounded by earthen dikes or fire walls of such dimensions that they can contain the entire contents of the full tank in case of an accidental rupture of the tank. The tanks themselves usually are equipped with floating roofs to eliminate breathing losses from evaporation.

C. Other Mitigating Measures

1. Special Stipulations

Leases for oil and gas exploration and development are subject to all OCS operating regulations and orders. Additionally, in some cases the lease may include special stipulations which are considered necessary for the protection of a particular resource , or activity, such as the one presented in Part B. above. These stipulations can be designed to meet the needs of a particular resource, e.g., wildlife or waterfowl refuges, fishing areas, certain recreation areas, protection of archeological or historical values, etc., which might be quite sensitive to development of the lease.

2. Notices to Lessees and Operators

These notices have the same effect or status as OCS Operating Orders and Regulations and are used when expeditious clarifications or corrections and additions to existing orders and regulations are necessary. By issuing Notices to Lessees and Operators, the extensive amount of time necessary to amend and republish orders and regulations is avoided. One example of a Notice, issued December 11, 1972, explains and details conditions for approval of waste water (oil field brines) disposal from OCS offshore facilities. This Notice provides that such discharges shall meet applicable EPA or State standards for effluent limitations, whichever are more important, and provides for certain monitoring activities. The ban on offshore use of PCB's was implemented by such a notice. Minimum geophysical survey requirements to comply with the stipulation to protect archeological and historical resources are also the subject of a Notice to Lessees.

3. Departures

A departure (waiver) from OCS Orders or other rules of the GS Supervisor may be granted when such a departure is determined to be necessary for (30 CFR, 250.12(b)):

a) the proper control of a well,
b) conservation of natural resources,
c) protection of aquatic life,
d) protection of human health and safety
e) protection of property, or
f) protection of the environment.

Waivers are technically based decisions and are granted in situations only where expert judgment determines that better, safer operations would result from operations under the waiver.

4. Research on Advanced Technology

EPA and Coast Guard are conducting research on more efficient containment and recovery devices (booms and skimmers). The efficiency of booms and skimmers depends on sea state and spill conditions but in any case are never 100% efficient. When the results of these studies, and any other similar studies so indicate, the requirement for use of better techniques and equipment will be incorporated into the OCS regulations and orders as appropriate. If incorporated, the requirements will be applied to all leases.

5. Geophysical Information

The Geological Survey is aware of the effects of the near surface geologic environment on drilling, fixed structural emplacements, pipelines, etc. This knowledge is fundamental to a sound lease management program for the OCS.

Geophysical data, which show the shallow structural and sedimentary environment, are used to predict, and thus minimize, any geologic hazards to drilling operations and consequent possible dangers to the environment, from pollution. Surface and shallow subsurface geologic strata, seldom create insurmountable obstacles to a minimal risk program of exploration and exploitation of economically attractive structures.

High resolution geophysical data covering all tracts to be offered for sale will be purchased and analyzed by GS geophysical personnel. These data, in the area of coverage, provide definitive information on (1) thickness of the unconsolidated sediments (0-300 feet); (2) structural configuration on shallow seismic horizons (300-500 feet below ocean bottom); (3) sea floor anomalies, mud mounds, mud waves or potential slide areas; pipeline and other objects on the sea floor, and bore hole locations as interpreted from a combinated analysis of several geophysical measurements, and (4) bathymetry.

Information from these high resolution data are extremely useful in detecting shallow geologic hazards such as potentially unstable bottom conditions (mud waves, etc.), shallow faults, and in some cases, near surface gas pockets. When these features are identified prior to drilling operations, or platform construction, the operator is notified so he can take the necessary action to assure that his operation is conducted with maximum safety. This is a necessary part of an effective OCS lease management program.

High resolution geophysical data usually are not gathered until the tracts to be offered for lease are announced and therefore, they are not available prior to draft impact statement preparation to contribute to a preliminary near-surface analysis; however high resolution data will be available prior to the sale date to support both pre- and post-sale lease management activities.

The latest interpretation of high resolution bottom profile data will disclose any bottom and/or subsurface conditions that might pose special environmental hazards for drilling or producing operations in the Louisiana offshore area, and these will be made available to the Bureau of Land Management OCS Manager prior to his decision to issue a lease and to the Geological Survey Area Supervisor prior to his approval of drilling operations. The District Engineer, Geological Survey, will prohibit the location of platforms on areas of instability should the need arise, through his authority to issue or not issue permits for platform placement.

6. Conservation Practices

The Oil and Gas Supervisor, in the interest of conservation, is authorized pursuant to the Code of Federal Regulations, to approve well locations and well spacing programs necessary for proper development giving consideration to such factors as the location of drilling platforms, the geological and reservoir characteristics of the field, the number of wells that can be drilled economically, the protection of correlative rights, and the minimizing of unreasonable interference with other uses of the Outer Continental Shelf. The Supervisor draws his authority from the following regulations and OCS operating orders:

- 30 CFR 250.11 outlines in broad terms the Supervisor's authority to control development of the OCS to protect the environment, and to obtain maximum economic recovery of mineral resources under sound conservation practices.

- 30 CFR 250.16 authorizes the Supervisor to specify the permissible production of a well. Thereafter, OCS Order No. 11 establishes the production rate control at the

Maximum Efficient Rate (MER) of the well or reservoir. MER is defined in OCS Order No. 11, see Attachment G.

- 30 CFR 250.17 dealing with well spacing authorizes approval of well locations, platform locations, and lists factors for consideration in this regard.

- 30 CFR 250.30 requires lessee's compliance with OCS Orders as well as general regulations and demands all necessary precautions to prevent damage, waste, and injuries.

- 30 CFR 250.34 requires the lessee to submit to the Oil and Gas Supervisor exploratory drilling plans, lease development plans and applications for permits to drill prior to these drilling programs. The Oil and Gas Supervisor utilizes well information such as electric well logs, core information from other wells previously drilled in the vicinity of the proposed drilling program and geological and geophysical data and other pertinent reservoir information to determine the proper number of wells necessary for development.

- 30 CFR 250.50 grants the Director authority to demand pooling or unitization which the Secretary is authorized to require under the OCS Lands Act in the interest of conservation.

- 30 CFR 250.51 refers to the unit plan regulations contained in 30 CFR 226 with regard to obtaining approval of units or cooperative agreements.

- 30 CFR 250.52 lists purposes for which the Supervisor may approve pooling or drilling agreements.

V. UNAVOIDABLE ADVERSE ENVIRONMENTAL EFFECTS

Certain features of oil and gas operations cause adverse effects which may be considered unavoidable in the light of current operation practices, technology, and regulations. A capsule summary of the significant effects are identified below.

A. Effect on Marine Organisms

Several oil and gas operations result in temporary increases in turbidity. These operations include the discharge of drilling fluids and the excavation of pipeline trenches by jetting and dredging. When turbidity is generated near the water surface, the depth of penetration of sunlight is diminished. This leads to a decrease in the output of the photosynthetic mechanism of the phytoplankton. The dimensions of the area affected are small and consist of a plume hundreds of yards in length. The duration of the turbidity in a given location will be several hours if the source is drilling fluid discharge. The effect of any decrease in primary production must be considered adverse. The area involved is very small and any reduction would only occur locally and would not involve the entire population of marine organisms.

Clogging of respiratory surfaces and filter-feeding mechanisms could reach a severe level in the benthic animals, however. The result of turbidity will be physiological stress, and possible mortality. This impact will be encountered during pipeline jetting operations and will be restricted to the downstream direction of the ocean current. The duration of the impact in a given area will probably be a few hours, but if it occurs in shellfish beds or other concentrations of organisms, the impact could be extremely adverse.

Beneath every platform where wells have been drilled is an expanse of cuttings, released during drilling, which has buried all non-motile forms below it. If the cuttings are different in texture and composition from the surrounding sediment, they will likely not be soon recolonized by local forms. Depending on the areas selected for lease sales, upwards of 500 platforms may eventually result from this proposal, resulting in approximately 1500 acres being covered with concomitant loss of biota.

Exposure of biota to harmful or toxic materials such as crude oil from spills, fuels and solvents, and discharged formation waters will produce an adverse effect. The effects of heavy concentrations of crude oil and petroleum derivatives include lethal toxicity, sub-lethal effects, coating with weathered oil, behavioral and habitat changes. The more subtle effects of light but repeated contamination may be serious also, but are not well understood at this time. More specific effects are:

1. Marine phytoplankton suffer stress and mortality when exposed to oil in the laboratory.

2. Copepods can ingest and pass oil droplets without apparent harm, but their position in the food chain may allow oil to move up the chain, to more susceptible organisms.

3. Plankton present near the core of a formation water plume will suffer stress and mortality from the higher temperatures, high mineral content, or lack of oxygen in formation waters. This adverse will likely not be noticed at the population level.

4. Laboratory experiments show that fish eggs and larvae may be killed by exposure to crude oil, due to clogging of respiratory surfaces. Formation waters may also adversely affect eggs and larva

5. Vegetation may be affected by pipeline leaks near- or onsho ,
as well as by spills from onshore facilities. Small leaks may do little damage, but severe leaks may contaminate the substrate. Seve l years may be required for recovery.

6. Large numbers of bird deaths have been an obvious feature of past oil spills. This adverse effect is highly probable, once a large oil spill occurs.

Quantification of the various amounts of different effluents is difficult, and can only be based on the historical information available from Gulf of Mexico experience. It must also be recognized that new effluent limitations may be applied to operations in new areas, through revision of operating orders and the development of special stipulations for that purpose.

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For the approximately 4000 wells in production in the Gulf of Mexico, about 603,000 bbl. per day of formation waters are produced. Approximately 305,000 bbl. of this amount are piped ashore for separation and treatment; the remaining 298,000 bbl. per day are either re-injected into the wells or discharged overboard. The amount discharged is not known, but it must be treated so that the discharge averages less than 50 ppm of oil. If the entire amount is discharged, this amounts to 75 bbl. of formation water being discharged per well per day. The water mix from the Gulf of Mexico is rather high, and other areas can be expected to produce less formation water per well.

Sewage and other solid waste can not be disposed in untreated condition under current operating orders (this condition is not expected to change in new areas). They must be transported to shore or incinerated (OCS Order No. 7). In general practice, these materials are compacted and incinerated. Some small amount of air pollutants is produced, and the ash is disposed at sea. Quantification of this discharge has not been accomplished.

Regarding oil spills from various sources (platform fires, blowouts, pipeline accidents, etc.), there have been 44 oil polluting incidents in the Gulf of Mexico from 1964 to April 1974 with a magnitude greater than 50 barrels. The total spillage was 320,000 bbl., over half of which was caused by a pipeline break in 1967 caused by an anchor dragging. New regulations concerning pipeline burial mitigate a recurrence of this type of accident. Since the regulations have been in effect (1970), the spillage rate from all sources has been 0.0017% of the total production of 2.9 billion bbl. of oil and condensate. Estimates of total amount of production that might result from the 10 million acre proposal are very tenuous. The best available estimate of anticipated production from high potential areas (10 million acres leased) is between 10 and 15 billion bbl. of oil. At the spi-lage percentage quoted above, this translates to a spillage of 170,000 bbl, and over a 20 year span of production, this would be 8500 bbl per year spilled from all operations.

Drilling muds contain compounds possibly toxic to marine life, particularly chromium compounds. Muds are disposed at sea, but the volum is difficult to determine. As long as good mud characteristics are maintained, mud can be reused in other wells. Eventually a point is reached (after one or many wells) when the mud can not be used. At this point, the bulk of the mud (a weighting component, barite) is removed by centrifugation and shipped to shore for reclamation. The remainder is discharged at sea. A typical 10,000 foot well in the Gulf of Mexico requires 300 long tons of mud components mixed with 7000 bbl of seawater, Of this amount, approximately 240 long tons are barite, which is mostly recovered. If 10,000 wells are drilled as a result of this proposed action, mud is used for five wells before disposal, and there are 10 years of drilling activity, then approximately 12,000 bbl of mud components (less barite) will be dispensed at sea per year of operations.

Damage to immobile, attached and rooted organisms during excavation and reworking of sediments and soil, and suspension of sedimentary materials can occur from entrenching of subsea pipelines, burial of pipelines through beaches and coastal wetlands. During emplacement of pipelines, sediments and benthic animals are washed out by hydraulic jetting. Softer life forms are likely to be killed, others made vulnerable to predation, and, in areas adjacent to down-stream ocean currents, some burial and smothering can be expected. The effect is limited to local areas around pipeline paths. In these areas, the effect is adverse and unavoidable.

According to USGS estimates, if leasing occurs similar to the scenarios presented in Section VIII. Alternative Sale Scheduling, approximately 8600 miles of pipeline will be necessary as a result of the scheduled sales, and approximately 6600 miles of pipe will be needed if the frontier sales are held in Gulf of Alaska and the Atlantic.

B. Wetlands and Beaches

Disturbance of beach and wetlands biota during pipeline burial by the trench and backfill method, uproots all plants and non-motile animals in the path of the pipeline, leaving a barren strip many feet wide. Some slight damage may also be rendered to vegetation in adjacent areas by machinery used in the operation. The effect is localized, but adverse for the smaller organisms destroyed. No estimates are available for the number of miles of pipeline in the marshes of Texas and Louisiana.

If an oil spill impacts upon a beach then there will be an adverse effect, which may last from weeks to several years or more, depending on the amount of oil, and size and location of the area impacted. Heavily contaminated beaches will be rendered unsuitable for recreatio so long as they remain contaminated with oil. If mechanical means are employed in beach clean-up operations (bulldozers, front end loaders and other earth moving equipment) as was done following the Santa Barbara and *Arrow* oil spill incidents, then shoreline equilibriu may be upset by beach removal. Excessive removal of beach materials can lead to erosional problems unless enough sand and gravel, or other suitable replenishing material is available to replace the removed beach materials.

In the history of OCS leasing, there have only been a few severe incidents related to offshore operations that have affected beaches. Two notable ones are the Chevron fire and the Santa Barbara spill. Most of the 44 oil polluting incidents mentioned previously have dissipated at sea, with only some very weathered oil reaching shore in small quantities.

C. Deterioration of Air Quality

Air quality will not be seriously impaired by routine operations, however, degradation could result from several types of accidents.

If a natural gas leak or gas well blowout should occur, pollution would be mostly from methane which quickly disperses and drifts away. In areas of sour crude, sulfur compounds may also be released. If a fire results, pollutants would be largely carbon dioxide and water vapor.

Oil leaks and oil spills not accompanied by a fire, would introduce highly volatile, low molecular weight hydrocarbons, such as benzene - and toluene, into the atmosphere. These lighter fractions of crude oil would undergo some unknown degree of degradation, but resultant photochemical smog is one possibility. If the spill results in a fire, large amounts of particulate carbon, and oxides of carbon, along with unknown amounts of sulfur oxides, nitrogen oxides, evaporated crude oil liquids, and partially oxidized compounds, would enter the air. Local air quality would be severely degraded during the period of the fire. This effect, should a fire occur, would be considered adverse and unavoidable.

Information from USGS indicates there were 38 gas leaks assciated with blowouts in the Gulf of Mexico from 1956 to 1973. Additionally, there were 44 oil polluting incidents from all operations in the Gulf from 1954 to 1974.

D. Deterioration of Water Quality

Degradation of water quality by routine operations will be slight. Brines added to sea water quickly diffuse into the water column.

Moderate to severe degradation would occur, however, in the event of an oil leak or spill. The effects of water quality degradation on the biotic community would be the major concern if this occured. In addition, water quality degradation will occur onshore if produced waste water is transported to shore for treatment and then discharged into fresh or brackish water systems which is the case when operators fail to follow state water quality standards.

The incidence of spillage of formation waters and drilling muds must be considered routine, after treatment for entrained oil. Estimates were developed in previous sections of 75 bbl. of formation waters per well per day and 12,000 bbl. of mud per year would be disposed under accelerated leasing. For the expected production of oil under this acceleration, approximately 8500 bbl. of oil will be spilled, also contributing to a deterioration in water quality.

E. Interference with Commercial Fishing Operations

As described in earlier sections, trawling operations suffer interference and inconvenience from oil and gas operations in several ways. A small portion of sea floor may be occupied by drilling rigs and platforms and becomes unavailable to trawl fishermen. Trawl nets can become snagged on underwater stubs and unburied pipelines, causing damage, to, or loss of, the nets. Less frequently, large objects lost overboard off petroleum industry boats and platforms are caught in trawling nets, resulting in damage to the net and/or its catch of fish. The frequency of occurrence of this type of incident is unknown.

A normal jack up rig directly removes about three acres of bottom from trawling operations, plus a safety distance. Estimates run from 500-1000 on the number of platforms it will take to produce the anticipated oil and gas from leasing 10 million acres. This will result in a minimum of 1500 acres of bottom being removed from trawler operations.

Although commercial fishermen could be expected to move out of the area of an oil spill, spilled oil could coat or contaminate commercial fish species, rendering them unmarketable. This would be another adverse effect to commercial fishing. Fouled gear and boats would reduce fishing effort and hence the catch.

F. Interference with Ship Navigation

Very little interference can be expected between drilling rigs and platforms and ships that are utilizing established fairways. However, at night, and especially during rough weather, fog, and heavy seas, ships not navigating the fairways could collide with fixed structures. Fishing boats engaged in trawling will be inconvenienced by having to navigate around fixed structures located on fishing grounds.

Increased leasing in areas where oil and gas operations are current being conducted will not significantly affect ship navigation, as ships are familiar with navigating in these waters and maintain awareness that platform locations must be known from charts and visuals. Some interference with direct line navigation can be expect

In frontier areas, leasing will lead to drilling rigs and platforms in areas where none presently exist. Estimates from USGS indicate that approximately 600 platforms may eventually result from sales in South Texas, Southern California, Central Gulf, and Cook Inlet; probably 400 more could be expected in other reasonably prospective frontier areas. These platforms will constitute an obvious interferen with ship navigation, but judging from the experience in Louisiana and Texas, this interference is easily avoided and not particularly bothersome.

G. Damage to Historical and Archeological Sites, Structures and Objects

Should an archeological or historical site on the OCS go undetected by the geophysical surveys required pipeline burial or the construction of a platform could damage the site. However, the above mentioned surveys are designed specifically to keep the occurrence of this type of damage to a minimum.

Other damage to archeological resources could come from oil contamination. Historical and archeological materials soiled by an accidental oil spill may not survive subsequent cleaning and restoration efforts. Porous materials could be rendered unsuitable for carbon dating techniques. Although the probability of such an incident occurring does exist, the potential for significant historical resource destruction appears small.

The significance of damage to these sites and objects is that damage or destruction precludes meaningful study of the Nation's and the continents heritage. Most artifacts are quickly destroyed by natrual elements; the small amounts of remains are very valuable and in some cases the only clues we have to the life styles of previous inhabitants.

H. Interference with Recreation Activities

Interference with recreation is closely related to degradatio of aesthetic values. Oil contaminated beaches, freshly cut pipeline routes, terminals, and other onshore support facilities would normall be avoided by those seeking recreation sites for use or development. Disturbance of beaches by pipeline burial operations is bery short-lived, relative to recreational use. Oiled beaches may require days, weeks, or years for adequate restoration depending on the initial severity and location.

Curtailment of recreational activities near coastlines is generally regarded by users as abusive, whatever the cause. Primary users are denied recreation and relaxation deemed necessary by most people for continued mental and emotional health, which in turn allows them to continue productive work. The curtailment also reduces income to recreational suppliers and services in and near affected areas, thus having a direct economic affect.

From a recreation standpoint alone, in terms of usage, different areas are of different importance. Areas such as southern and central California, Galveston and upper Texas, southern (Atlantic and Gulf) and panhandle Florida, New Jersey, Long Island, and much of the New England coast are all highly valued and highly used areas. Other areas are generally of lesser importance, in terms of recreatio

I. Degradation of Aesthetic Values

It is possible that some portion of platforms, drilling rigs, traffic, and other structures and activities of the oil and gas industry will be visible to a shoreline viewer. If these objects interfere with residential or recreational vistas, the visual effect would be considered adverse by some persons. Night lighting may also be aesthetically unpleasant to some.

Noise from equipment, aircraft, and other traffic associated with gas and oil production and exploration may be objectionable to residents or visitors of an affected area. Within very local areas, increased noise levels may also disturb birds and wildlife during critical life stages (nesting, breeding, etc.).

Odor from oil and gas operations (refineries, treatment plants, etc.) may adversely affect the aesthetic qualities of some areas. Operations involving sour crudes with high sulfur content have a greater potential for producing an odor problems.

The obvious significance of such degradation is a reduction in the quality of living for those people who dislike the sight of rigs from pristine shores, and the nearby risk of oil spills. The more highly used areas like Southern California and the northern Atlantic Coast will have more people who are disturbed by this factor.

J. Conflict with Other Uses of the Land

If sites in agricultural areas, the construction of pipeline terminals, or other onshore facilities will remove temporarily small amounts of land from grazing or farming use. Interruption of farming activities until the following growing season usually results. The existence of pipeline terminal facilities would involve the permanent loss of up to several acres for grazing or farming, because each facility usually requires an access highway and is enclosed by a fence A pipeline leak or tanker spill, however, involving the release of oil into farm land would render the land contaminated and unsuitable for grazing or other agricultural purposes. One or more growing seasons might be required for recovery of affected vegetation and degradation of spilled oil.

A possible conflict exists with the siting of offshore structures and the siting of deep water ports. The U.S. currently has no deep water ports but they will be almost necessary in the future. Several sites are being investigated, including offshore Delaware, and Louisiana, and Galveston and Corpus Christi. Adequate planning can reduce any potential conflict.

VI. RELATIONSHIP BETWEEN LOCAL SHORT-TERM USE AND MAINTENANCE AND ENHANCEMENT OF LONG-TERM PRODUCTIVITY

The principal short-term use of any specific sale area will be the extraction of oil and gas from those tracts which prove economically productive. This mineral extraction will contribute to the diminishment of the long-term productivity of the oil and gas resources of the area and possibly to marine and coastal resources.

Oil and gas have been extracted from Louisiana OCS areas for many years, and, although no decrease in marine productivity has been detected, it is recognized that chronic low-level pollution from oil and toxic chemicals may impact adversely on long-term productivity. It is possible that development of frontier areas will result in degradation of long-term productivity, but the long-term effects of low-level pollution are not clearly understoon at this time.

The term "frontier area" has been used throughout this statement to denote geographic regions that have no history of OCS oil and gas recovery operations. In reality, however, many of these areas are under stress due to environmental loadings similar to the types of loadings that OCS development would produce. Heavily industrialized and populated areas such as much of the Atlantic and California coasts are already stressed offshore by oil and other hazardous substances, such as sewage dumping and polluted river outflow. Porricelli and Keith (1973) calculated the amount of oil pollution to the ocean from various sources:

Source	Percentage of Total Ocean Oil Pollution
Automobile crankcase oil disposal	29.4
Tankers	28.4
Other Vessels	17.3
Industrial machinery waste oil	15.3
Refinery/petrochemical plant disposal	6.1
Offshore production	2.1
Tank barges	1.4

Few areas will be found free of such oil pollution, and to the extent areas are stressed by oil pollution and other substances, the consequences of OCS development will be a small or large increase in environmental loading. An analysis of these areas is not attempted in this statement, but the readily apparent areas of Alaska, the northern Pacific coast, and parts of New England will probably suffer the largest stress because of OCS development.

The additional stress which the ecosystem can absorb is limited, but at present, the bounds of these limitations are not known. St. Amant (1970) observed, "Certainly the significance of the continual addition to, and accumulative effect of, sublethal pollutants in the environment is probably the most important ecological question facing us today."

Disturbance of coastal land by pipeline construction and burial operations and construction of related onshore facilities will decrease productivity in the short-term only. Productivity of coastal lands in the area disturbed by pipeline operations will actually increase following the disturbance, and will fall off to natural levels as original conditions are restored in subsequent growing seasons. During the restoration period, light grazing or farming pressure most likely will not have any effect, but heavy grazing or farming could serve to keep the disturbed area from recovering at an optimum rate. Species diversity in the disturbed area will be low during the recovery period.

Based on past leasing and exploration experience, as many as 1600 new platforms may be required to explore and develop 10 million acres as a result of this proposal. More structures are required as OCS production increases and new geographic areas are opened to drilling and, although concomitant cessation of production in older fields results in removal of some platforms, the cumulative impact of structures on multiple-use of the OCS is a point of concern. The cumulative impact of structures as hazards to commercial shipping, and as obstruction to commercial fishing activities, represents a conflict that can be controlled through proper planning and coordination with the appropriate Federal and State agencies and private industry. Some leveling out in the number of platforms is expected as older fields become inactive or hydrocarbon production decreases. This is also true with regard to the cumulative numbers and length (in miles) of pipelines coming ashore. In the case of pipelines, as more and more areas begin to approach termination of production, some additional capacity will be available in existing pipelines to carry production from new areas thereby reducing the numbers of new pipelines required from subsequent lease sales. We are unable to determine at this time if the total number of platforms and pipelines required to develop the OCS areas in the Gulf of Mexico has peaked, but indications are that conditions are approaching a leveling off point.

But for several years, the leasing of 10 million acres will represent a tremendous strain on steel mills, platform construction firms, and the pipe manufacturers to supply the necessary materials. For those years when construction is occurring (5-8 years), there will be a continual increase in the number of platforms and pipelines on the OCS. Modification of the amount of acreage leased annually in future years would probably result in a downturn of construction and OCS installation, but this can only be done when the feasibility of leasing 10 million acres is determined.

VII. IRREVERSIBLE AND IRRETRIEVABLE COMMITMENT OF RESOURCES

A. Mineral Resources

The leasing of 10 million acres of OCS lands in 1975 could eventually result in the extraction and depletion of up to 50 billion barrels of oil and up to approximately 250 trillion cubic feet of gas. This constitutes an irreversible and irretrievable commitment of resources.

An additional consideration is that this oil and gas will be extracted from high potential sites in several frontier areas of the OCS. Leasing in future years will probably occur in the remainder of the high potential frontier areas, and in the high potential tracts within these areas. While it is one of the goals of Project Independence to begin acquiring the more readily available reserves, a secondary effect occurs. With this commitment of more easily obtained oil and gas, development of secondary and tertiary recovery technology is delayed. Unless incentives are developed for research into these technologies, a more dramatic crisis of energy supply may occur in the longer term.

B. Land Resources

The implementation of this proposal will necessitate the expansion of onshore facilities. New facilities will have to be built in areas near development sites; if nothing else, there will have to be pumping facilities to transport the fluids produced. As many as 140 onshore facilities and 200 pipelines (including gathering lines) could be necessary as a result of this proposal. The acreage devoted to accommodating these onshore facilities and onshore pipeline traverses will represent an irretrievable commitment of the land.

The construction of new refineries in onshore areas near the new production anticipated from this proposal is a slight possibility. Construction of refineries requires a large capital outlay and has recently been met with strong citizen opposition on the east coast. We have no indication of proposed refineries at this time; the increased production that will result from this proposed action will be transported to existing refineries and replace imported crude oil and natural gas in the energy supply mix.

C. Fish and Wildlife Resources

An irreversible or irretrievable commitment of fish and wildlife resources and their habitats could occur in the area of a massive oil spill or if frequently subjected to chronic low-levels of oil pollution. At this time, there is insufficient evidence to conclude that low-level spillage has led to an irreversible commitment of fish and wildlife resources but there is enough evidence to indicate that this is a possibility that deserves close attention, and constant study. The magnitude would approximate the current irretrievable losses that have resulted from operations in the Gulf of Mexico, as the acreage currently under lease there is about the same as proposed for this expansion.

VIII. ALTERNATIVES TO THE PROPOSED ACTION

A. Alternative Sale Scheduling to Increase OCS Leasing

1. Description

a. Comparative Analysis of Possible Lease Areas

The integration of the ten million acre proposal with the existing schedule of offering three million acres per year was mentioned in Section I on the Description of the Proposed Action. The proposed schedule - provisional OCS leasing indicates sale #37, Louisiana and Texas, sale #38, Gulf of Mexico, and sale #39, Gulf of Mexico as scheduled to be held in 1975. Since the issuance of the schedule in July, 1973, several changes have taken place. Sale #37 has been redesignated as a sale in the South Texas area. Sale #35, Southern California was not held in 1974 but is now proposed to be held in 1975. Also, the Federal Government and State of Alaska mutually agreed to explore the feasibility of conducting the Lower Cook Inlet (Sale #43) in 1975, if litigation regarding jurisdiction of the area could be resolved.

Decisions on whether to hold lease sales in any area will not be made until the completion of all necessary studies of the environmental impact and the holding of public hearings. Environmental, technical, and economic studies may effect decisions not to hold any given sale.

The intention of the Department is to lease 10 million acres in 1975. A Departmental objective in the annual work plan for 1975 is the offering of 14.5 million acres of OCS land for oil and gas development. This should be viewed as a conservative estimate of the amount of land that must be offered in order to eventually have 10 million new acres under lease. Recent experience in the Gulf of Mexico shows a lease-to-offered percentage ratio between 40 and 50%. From this percentage, the projection would be that 20 to 25 million acres would have to be offered to lease 10 million. However, several sales have already been held in Louisiana and Texas waters, and it can be assumed that some portion of the prime acreage has already been leased. If only prime acreage is offered under the 10 million acre proposal, the leased-to-offered percentage could be somewhat higher, resulting in less acreage having to be offered. Also, much of the Louisiana-Texas OCS is gas-prone, which makes it less interesting to the major oil companies. It is anticipated that the total amount of acreage that must be offered in order to lease 10 million acres will fall between 14 and 19 million acres.

In 1974, the amount of acreage offered was accelerated to nearly five million acres. With one remaining sale in 1974 (offering 1.4 million acres), slightly over one million acres have been leased in the Gulf of Mexico this year. In light of this fact, and the fact that only a little more than six million acres have been leased in the OCS program to date, the proposed action is a significant increase. Again it must be stated that this increase will not be effected until all necessary site-specific impact statements for given sales are completed.

With the preceding proviso in mind, the following areas are scheduled to be leased in 1975, under the three million acre schedule. South Texas #37 is scheduled to be the first sale in 1975; the draft impact statement has gone out for public and agency review and a public hearing is scheduled to be held on September 26-27, 1974. A total of 3.1 million acres are being offered in that sale. The timing and sequencing of the remaining sales in 1975 are still in the planning stages.

The following scenarios indicate possible schedules that could be followed in implementing the ten million acre proposal. There are variations in sequencing (South Texas #37 is always first) and in sizes of potential sales.

	Area	Expected Leasing(millions of acr
1.	South Texas	1.5
	Cook Inlet	1.0
	Gulf of Mexico	2.5
	Southern California	1.0
	Frontier Area	2.0
	Frontier Area	2.0
2.	South Texas	1.5
	Southern California	1.0
	Gulf of Mexico	2.0
	Cook Inlet	2.0
	Frontier Area	2.0
	Frontier Area	1.5
3.	South Texas	1.5
	Cook Inlet	2.5
	Southern California	1.0
	Gulf of Mexico	3.0
	Frontier Area	2.0

For the areas that are scheduled to have sales, the sequencing and sizes (up to the limits of acreages where reserves are likely to be found) can be adjusted in as many combinations as possible. The significant point of the scenarios is the necessity of conducting sales in one or two frontier areas. Scenario #3 indicates a schedule that has only one frontier sale, but it is a two million acre sale. It may not be desirable to conduct that size sale in a frontier area. Thus, scenario #3 could have two sales in frontier areas of one million acres each, and the frontier area having two million acres offering in scenarios 1 and 2 could be reduced; the extra million acres could be made up in Cook Inlet.

It must be recognized that the South Texas area is a frontier area and that Cook Inlet and Southern California have only had limited production to date. Thus, it is effectively a five frontier opening of areas for leasing in 1975 that is being considered in this proposal. Individual sale impact statements of a more detailed and analytical nature than this document will be prepared for each sale area. Environmental baseline studies are in planning for three of these areas and will be conducted in each frontier area opened for nominations as they are delineated. Possible frontier areas to be included in the 1975 ten million acre proposal are analyzed in the following section.

b. Preliminary Lease Area Ranking

Several rankings of OCS regions have already been developed in other offices. The CEQ ranked areas of the Alaska OCS and Atlantic OCS on the basis of relative environmental risk. The following table indicates the CEQ ranking, with lowest risk at the top:

Eastern Georges Bank
Southern Baltimore Canyon
Western Georges Bank
Central Baltimore Canyon
Northern Baltimore Canyon
Southeast Georgia Embayment
Western Gulf of Alaska
Eastern Gulf of Alaska

On February 20, 1974, the Department of the Interior requested that oil and gas companies rank the 17 OCS areas discussed in this statement by order of oil and gas potential (see Attachment C) was also requested that the general public rank the same areas on the basis of environmental concern. Twenty-five oil or oil-related industries responded to the resource potential question; several of these also indicated areas of environmental concern. A total of 63 responses were received (see Attachment G).

The following table is the composit ranking of areas by resource potential that derives from industry responses.

Ranking by Resource Potential from Greatest to Least

1. Gulf of Alaska
2. Central Gulf of Mexico
3. Beaufort Sea
4. Bristol Bay
5. Southern California Borderland
6. Eastern Gulf of Mexico
7. Western Gulf of Mexico - Middle Atlantic
8. North Atlantic
9. North Atlantic
10. Santa Barbara
11. Bering Sea
12. Chukchi Sea
13. Cook Inlet
14. South Atlantic
15. Southern Aleutian Shelf
16. North and Central California
17. Washington - Oregon

Four petroleum companies ranked the frontier areas according to relative leasing priority, based on potential and material availability. The following ranking has the most preferred area at the top.

1. Mid-Atlantic
2. Gulf of Alaska
3. Cook Inlet
4. Santa Barbara
5. North Atlantic
6. Bristol Bay
7. Beaufort Sea
8. Chukchi Sea
9. Southern Aleutian Shelf
   South Atlantic
10. Bering Sea Shelf
11. North and Central California
12. Washington-Oregon

Combining these two rankings produces the following composite ranking of resource potential and order of preference:

1. Central Gulf of Mexico
2. Gulf of Alaska
3. West Gulf of Mexico
4. Southern California Borderland
5. Mid-Atlantic
6. East Gulf of Mexico
7. North Atlantic
8. Bristol Bay
9. Beaufort Sea
10. Santa Barbara
11. Cook Inlet
12. Bering Sea
13. South Atlantic
14. Chukchi Sea
15. Southern Aleutian Shelf
16. Northern-Central California
17. Washington-Oregon

The Geological Survey has provided estimates of the undiscovered recoverable reserves for the same 17 OCS areas. Although their estimates were ranges with the lower ends set at 0, the upper ends can be used as a ranking by resource potential. This ranking from greatest potential at the top is:

1. Western Gulf
Eastern Gulf
3. Central Gulf
Gulf of Alaska
Bering Sea
6. North Atlantic
Middle Atlantic
South Atlantic
Cook Inlet
Bristol Bay
Chukchi Sea
Beaufort Sea

12. Aleutian Shelf
13. Southern California
Santa Barbara
Northern California
17. Washington-Oregon

Four industries ranked the areas for environmental hazard. Factors affecting these rankings were identified, but detailed analysis was not submitted. This listing, in order of increasing environmental hazard is:

1. Western Gulf of Mexico
2. Central Gulf of Mexico
3. Eastern Gulf of Mexico
4. North-Central California
5. South Atlantic
6. Southern California - Santa Barbara
7. North Atlantic-Middle Atlantic
8. Washington-Oregon
9. Cook Inlet
10. Chukchi Sea
11. Beaufort Sea
12. Bering Sea-Gulf of Alaska
13. Bristol Bay

2. Environmental Impacts

The types of impacts that expanded OCS oil and gas leasing would produce were discussed in Section III. The alternative sale scheduling just discussed (Sec. VIII.A.1.a.) represents several options for leasing 10 million acres of high potential OCS land. The environmental impacts from leasing under these various options are relatively the same in aggregate terms, as several of the areas have already been designated for sales (under the Five-Year Schedule, July 1973) and the high potential acreage in each area is limited. The probabilities and kinds of impacts have been previously described, where known; the severity of possible impacts is dependent on development intensity. Development intensity will be determined by two factors: the amount of acreage offered (and leased) in a given area and the prospects for the area. The amount of acreage offered is designated by Department of Interior under the pre-sale program described in Section I. On this basis, some projections have been made under different options of the potential impacts of the program in different area. However, it must be recognized that the more critical factor is determining potential impacts is the hydrocarbon (especially oil) potential in an area. Only through the knowledge gained from extensive seismic work and, of most importance, exploratory drilling, can adequate estimates be made of recoverable resources. These estimates in turn allow determinations to be made on the numbers of platforms, wells, pipelines, onshore facilities and ancillary activities necessary to develop these resources. Drilling operations are the most critical period wher severe impacts might possibly occur to the ocean and shoreline, while pipelines and onshore facilities cause disruptions in coastal ecosystem and land use. These can not be accurately predicted without firm estimates of producible reserves, estimates which derive directly from exploratory drilling.

VIII. Alternative to the Proposed Action

B. Increase OCS Leasing in Modified Form

1. Description

a. Increase OCS Leasing in Shallow Water Areas, but Postpone Leasing in Deep Water Pending Evaluation of Operating Experience from Deep Water Tracts Leased Previously

As of January 1974, 5.65 million acres are still under active leases of the 10.6 million acres that have been leased since 1953. Most of this acreage occurs in shallow water, i.e., in water less than 200 meters deep. The alternative is to lease more acreage in shallow waters as opposed to areas in deep water.

The advantage of leasing only shallow water areas in frontier regions is that is would give industry time to gain experience with those deep water tracts that have already been leased. Also, it would give industry time to gain experience in frontier regions after leases have been awarded for shallow water tracts. A disadvantage is that leasing in shallow water areas may entail greater environmental risk than leasing in deep water, due to closer proximity of high value shore resources.

b. Other Increased Leasing Alternatives

One alternative is to lease structures as opposed to leasing tracts. A tract on the OCS does not necessarily occur congruent with a suitable geologic structure. Therefore, a tract

may cover a complete structure, part of a structure. or no structure. If complete or whole structures are leased on frontier areas, the structure could be developed as a unit as opposed to developing a single tract.

A problem with this proposal is that some structures are so large that a great deal of capital would be needed for the bonus. This could be mitigated by a royalty bidding plan. Another problem is the definition of a structure and its boundaries. The U.S. Geological Survey would be responsible for determining the exact position of structures for leasing, but many times such boundaries are vague.

c. Analysis of Various Levels of Increased Leasing

Production of oil and gas on OCS land presently under lease is currently running at 0.5 billion barrels and 3.1 trillion cubic feet respectively on an annual basis. It would be expected that under accelerated leasing, the amount of oil and gas taken from the OCS would increase. The exact amounts of oil and gas that can be expected from various levels of increased leasing are not exactly known at the present time, mainly because a long term schedule has not been constructed, and lack of geological data for frontier areas. However, some general estimates have been made. These estimates are only generalizations and are not to be taken as absolute figures.

Area	PEAK PRODUCTION Oil (MM BOPD)	 Gas (BCF/D)
	(One Million Acre Sale)	
1. North Atlantic	1.4	6.9
2. Middle Atlantic	1.4	6.9
3. South Atlantic	2.1	11.0
4. Eastern Gulf	2.7	15.0
5. Central Gulf	3.8	18.0
6. Western Gulf	2.7	15.0
7. Southern California	1.4	2.7
8. Santa Barbara	1.4	2.7
9. North California	1.4	2.8
10. Washington-Oregon	0.55	0.8
11. Gulf of Alaska	2.7	14.0
12. Cook Inlet	1.8	9.2
13. Aleutian Shelf	1.4	6.9
14. Bristol Basin	1.8	9.2
15. Bering Sea	1.8	9.2
16. Chukchi Sea	1.8	9.1
17. Beaufort Sea	2.7	14.0
	(Three Million Acre Sale)	
1. North Atlantic	2.7	14.0
2. Middle Atlantic	2.7	14.0
4. Eastern Gulf	5.5	30.0
5. Central Gulf	5.5	28.0
6. Western Gulf	5.5	30.0
11. Gulf of Alaska	5.5	27.0
12. Cook Inlet	2.7	14.0
14. Bristol Basin	2.7	14.0
15. Bering Sea	4.1	21.0
16. Chukchi Sea	2.8	14.0
	(Five Million Acre Sale)	
15. Bering Sea	5.5	28.0

2. Environmental Impact

The possible environmental impacts of leasing only shallow water tracts (i.e., less than 200 meters) are several. Deep water drilling is not a thoroughly tested activity, but deep water tracts have been leased recently in the Gulf of Mexico. The development of these tracts could be intensively studied for their feasibility and safety aspects, while deep water tract leasing is suspended. Assuming a worst case, i.e., deep water drilling proves to be an inherently high-risk operation, the environmental impact of the alternative of suspension will be that the possibility of oil spills from deep water drilling operations will have been avoided. The evaluation of deep water technology will either substantiate that the technology is adequate for safety or point the way toward necessary design and operations modifications that will make this activity as safe as possible within certain economic limits.

On the other hand, if certain levels of production are the goals of leasing, then it will be necessary to lease more shallow water tracts to provide such supply. Shallow water tracts are closer to shore, so that, should an oil spill occur, there is a higher probability of it coming ashore in a less weathered state. This assumes currents and winds generally directed toward shore, a condition not always found

on different coasts. The current and wind regime in the 0-200 meter portion of the shelf would have to be analyzed for all areas to test this possible impact.

Leasing of structures rather than tracts would not change the environmental impacts significantly.

Any other modified leasing plan would offer less than 10 million acres in 1975. The magnitude of, or possibility of any or all adverse (and positive) environmental impacts would be reduced in appropriate proportion of the reduced offering.

C. No Increase in OCS Leasing

1. Description

The entire proposal of increasing lease acreage to ten million acres in 1975 could be voided. This would re-institute the current leasing schedule of three million acres per year and utilize the provisional schedule of geographical areas developed in July 1973. Under this schedule, the frontier area of South Texas, the expansion of drilling into Lower Cook Inlet and the resumption of drilling off Southern California were planned.

2. Environmental Impact

The impact of these actions, even though under the old schedule, would be significantly different than previous site-specific impact statements could describe. They would necessitate the first in-depth analysis of these areas under the environmental impact statement format. (This 10 million acre statement is not meant to substitute for this in-depth analysis). Thus, significant environmental analysis would still be required under the current leasing schedule, and the impact of the no-increase proposal is not being fully analyzed here. See next section on postponing the increase.

D. Postpone Increase in OCS Leasing

1. Description

a. Until New Technology is Available to Provide Increased Environmental Protection

The proposed increase in leasing could be delayed until new technology is available; however, basically safe technology is available provided its application and use are properly regulated and controlled. As new technology relating to safety and environmental protection is developed, it can be incorporated with existing requirements and applied to all OCS leases so that bringing on additional production now will not generally preclude adaptation of new advances to the prospective leases. "Zero risk" does not exist but is an idea toward which safety systems are directed. In the history of Federal offshore leasing and production over the past 19 years only 11 spills of 1,000 bbl. or more have occurred in more than approximately 1,500 leases, 10,500 drilling holes, and 1,939 producing platforms.

b. Pending Completion of Studies Concerning the Potential Environmental Impacts of Offshore Minerals Development in General and Oil Spills Specifically

The proposed acceleration could be delayed pending completion of all studies concerning the potential environmental impacts of offshore minerals development in general and oil spills specifically. Many long-term, ongoing studies relating to these issues are being conducted by the scientific community, industry, and government. The Bureau of Land Management is initiating long-term, ongoing studies of its own both on an inhouse and contract basis. See Section I.G. for a description of the Bureau's present study efforts relating to the OCS program.

A central feature of many of these studies is that they are never really completed in the sense that they rarely reach definitive conclusions with wide applicability, but simply advance from one stage to another, from one level of analysis to another, thereby contributing to a growing area of knowledge and body of literature pertaining to the numerous complexities of environmental analysis. To delay the sale on the basis of incompleted studies would require an indefinite delay perhaps of many years duration. As the recent University of Oklahoma study, "Energy Under the Oceans: A Technology Assessment of Outer Continental Shelf Oil and Gas Operations", pointed out, current and programmed research on OCS environmental data will help improve our knowledge; however, acquiring a total functional understanding of the coastal environmental is an "extremely long-term goal". Undoubtedly, information gaps and uncertainties will always be associated with offshore minerals development and any delays in such development programs must be judged on the basis of whether or not these gaps and uncertainties are so great, compared to what is known, as to warrant postponement. The OCS oil and gas leasing program will help make available increased supplies of energy resources of Federal lands for national energy needs. Final judgment must rest on a determination regarding whether or not a delay in the acceleration of leasing would be in the Nation's best interest.

c. Pending Development of Land Use and Growth Plans Onshor

The proposal could be delayed pending the development of land use and growth plans onshore. Timetables for onshore development of plans, updating, revisions, and subsequent implementation. Delay of the proposed awaiting such plans could cause the development of the offshore mineral resources to occur in a piecemeal, unorderly manner. It could result in a greater degree of coordinated planning between states and the Federal Government especially with regard to coastal areas and would result in the avoidance of potential environmental impacts resulting from lack of coordinated efforts. It should be stated, however, that onshore development must take place within the authority of state and local agencies, and coordination with the jurisdictional agencies is sought throughout the entire leasing and development process.

d. Pending Completed Implementation of Recommendations Made in Reports on OCS Operating Orders and Regulations and Review of Regulations and Amendment as Necessary

A decision could be made to delay the acceleration of leasing until the implementation of those recommendations made in reports concerning strengthening operating procedures had been completed. During the implementation of these recommendations, a review could be completed of all operating and leasing regulations, OCS orders, and statutory provisions to locate sections that needed revision. Any necessary amendments of the regulations and orders could be made through the appropriate procedures and if sections of the OCS Act were found to need revision, amendments could be suggested to Congress. In considering this alternative, the existing authority of the OCS Lands Act to prescribe and amend regulations at any time when the Secretary determines it to be necessary and proper so as to provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf and the protection of correlative rights therein must be kept in mind. 43 U.S.C. § 1334(a)(1). Any revisions of the operating regulations or the OCS orders which relate to the prevention of waste, conservation of natural resources, or protection of correlative rights could be made at any time and apply to all existing leases. It is unlikely, however, that amendments to the OCS Act or regulations dealing with matters other than the above could be applied to leases in existence at the time of the amendment. If such amendments were felt necessary for leases which may be executed if the proposed sale takes place, they would have to be done before the leases were signed by the parties.

2. Environmental Impact

A decision to delay the proposed action based upon any combination of the four reasons given above would eliminate any environmental impact to the offshore or onshore areas resulting from implementation of the proposal during the period of the delay. Assuming a decision was made to hold sales at future dates after all the reasons for delay had been satisfied, the environmental impact would reflect the degree of success achieved in attaining more fail-safe technology, baseline biological data against which the potential impacts could be assessed, land use development plans with which operations could be coordinated, and revised leasing and operating regulations and orders to strengthen the management of OCS operations and minimize the impact of such operations.

It is conceivable that the potential environmental impact of operations resulting from sales held after such a delay would be of much the same character as those potential impacts discussed in this statement, but that the potential for such impacts occurring would be minimized. Some impacts might be reduced entirely if changes in operating techniques were the result of the review conducted during the delay period. For instance, biological baseline data and other research might suggest that drilling muds are harmful when released into the marine environment. If such findings were made, different operating procedures would no doubt result to eliminate or reduce this impact. Such different operating procedures would have their own environmental impact which would have to be considered.

If the proposal were delayed for the reasons given, it is evident that the delay would be for more than just a few months. A delay of at least two years could reasonably be expected to complete baseline studies, develop improved technology, implement land use programs - particularly under the Coastal Zone Management Act, and implement the recommendations and regulatory changes discussed above. In the event of a delay of that duration, alternative energy sources would be expected to fill the gap left in the needed energy supply during that period. These alternative energy sources have their own environmental impact as discussed earlier in this section of the statement. Depending upon the alternative source or combination of sources drawn upon to meet the demand left unsatisfied by the delay of the proposal the environmental impact to the Nation could be more or less than that anticipated to result from the implementation of a 10 million acre goal in 1975.

E. Discontinue OCS Oil and Gas Leasing

1. Description

A discontinuation of OCS leasing would not necessarily cause a discontinuation of development drilling on leased tracts. Those tracts that have been leased would continue to produce oil, however, the leasing of new tracts would be discontinued. This would mean that large quantities of oil and natural gas that exist as indicated, inferred, and undiscovered reserve would not be produced. The U.S. Geological Survey has estimated that the total offshore (less than 200 meter water depth) indicated and inferred reserves of crude oil and natural gas liquids are estimated to range between 3 and 5 billion barrels (0-1.5, State; 3-5, Federal). Offshore estimates of such reserves of natural gas range between 23 and 45 trillion cubic feet (4-7, State; 19-38, Federal). Offshore (less than 200 meters water depth) undiscovered recoverable crude oil and natural gas liquids are estimated to range between 65 and 130 billion barrels (7-14, State; 58-116, Federal, and total offshore undiscovered recoverable reserves of natural gas are estimated to range between 395 and 790 trillion cubic feet (40-80, State; 355-710, Federal). These figures indicate the considerable hydrocarbon reserves that occur on the Outer Continental Shelf that would not be developed if OCS leasing were discontinued.

2. Environmental Impact

If OCS leasing was discontinued, there might be a greater environmental impact onshore due to the possible increase in the development of alternative energy sources such as coal, oil shale, tar sands, geothermal steam, etc. Alternative energy sources development would be necessary to offset the oil and natural gas production that would be lost to the supply market if OCS leasing would be discontinued. For a further discussion of these impacts, see the section in this report on energy alternatives which is VIII F.

F. Energy Alternatives

The U.S. energy mix has changed considerably since World War II. In 1947, coal contributed almost half of total energy consumed, followed by petroleum with one third of the total. Natural gas in 1947 contributed about 14 percent, and hydropower about 4 percent. Today, petroleum has displaced coal as the major source of energy, and contributed about 45 percent of energy consumed in 1973. Natural gas followed, with about one third coal about one sixth. Hydropower and nuclear together contributed about 5 percent.

Natural gas has become a major source of energy in the industrial sector, which received nearly half of total gas supplies in 1971. The major industrial users of gas are the chemical industries, the primary metal industry, and the energy industries themselves, particularly petroleum. The principal growth market for gas since 1947 has been the electric utility market.

Annual coal consumption in 1973 was about 100 million tons below the 1947 level. Since 1947, coal has lost most of its markets in transportation and space and process heating to oil, gas, and electricity. Total residential and commercial use of coal declined from over 22 percent of total coal supply in 1947 to about 3 percent. Industrial use also declined. Increases in coal demand for electric power generation have helped offset declines in other markets. In 1973, electric utilities accounted for almost two-thirds of total coal use.

Petroleum consumption of 1973 was more than three times the 1947 level. Transportation uses account for over half of petroleum demand. The most rapid growth in petroleum use has been for electricity generation.

Declining proved oil and gas reserves and the growing uncertainty over future availability of foreign imports suggest that the U.S. will face natural gas and petroleum supply problems in the near and long term. Significant expansion of coal supply faces manpower, capital, and environmental constraints despite abundant U.S. coal deposits.

Most of the primary energy resources that fuel our energy system, including coal, oil, gas, uranium, and hydroelectric power, are substitutable and competitive to an increasing degree. Within this context of substitutability, it is not likely that any major technological changes will occur in the next few decades. However, shifts within the resource mix can be expected in the form of increased use of coal, nuclear power, and development of synthetic fuels from coal and oil shale. Accelerated development of resources such as coal, petroleum, natural gas, oil shale, and tar sands, and the eventual depletion of these sources, will be accompanied by an evolution of technologies using solar and geothermal energy, fuel cells, magnetohydrodynamics, fusion, and others.

The discussion that follows treats each major energy source separately, and gives projections for its development. A detailed discussion of each major source, and other potential sources, including technology, resource base, costs and prices, and environmental impacts, is found in Energy Alternatives and Their Related Environmental Impacts (U.S. Department of the Interior, December 1973).

1. Increased Oil Imports

The U.S. has increasingly relied on petroleum imports to fill the gap between supply and demand. In the past, most U.S. imports originated in the Western Hemisphere. Future increases in imports from the Western Hemisphere are restricted by several considerations. In Latin America, increases in consumption are expected to be greater than increases in production. Canadian policy of energy self-sufficiency and plans for a pipeline connecting the western provinces, which have a surplus of oil, with the eastern provinces, which have a shortage, will limit future U.S. imports.

Future increases in oil imports will have to come primarily from the Middle East and North Africa. It has been estimated that almost 80 percent of the non-communist world oil reserves occur in these two areas. (Oil and Gas Journal, 1973).

Increased imports from the Middle East would bring problems with security of supply, balance of payments, and U.S. off-loading terminal capacity.

Availability of imports in the future is in question due to competition on the world market; increasing demand, declining resources, and conservation policies within some exporting countries (particularly Latin America); and manipulation of oil exports by exporting countries to apply political pressures.

The bulk of past oil imports has entered PAD I(66 percent of 1972 imports), which has a high concentration of population and industry and very limited oil production. Large deficits and demand for imports will likely continue in this District. In 1972, PAD District II had a large oil defecit which was filled by shipments from District III and imports from Canada. Increasing imports into District II would likely enter the Gulf Coast and would require expansion of transportation networks from the Gulf Coast to the Mid West.

It is likely that PAD District V will not need significant quantities of petroleum imports in the next decade or so if the Trans-Alaska pipeline is built. After 1985, increased demand may require imports. Projected level of oil imports are given below.

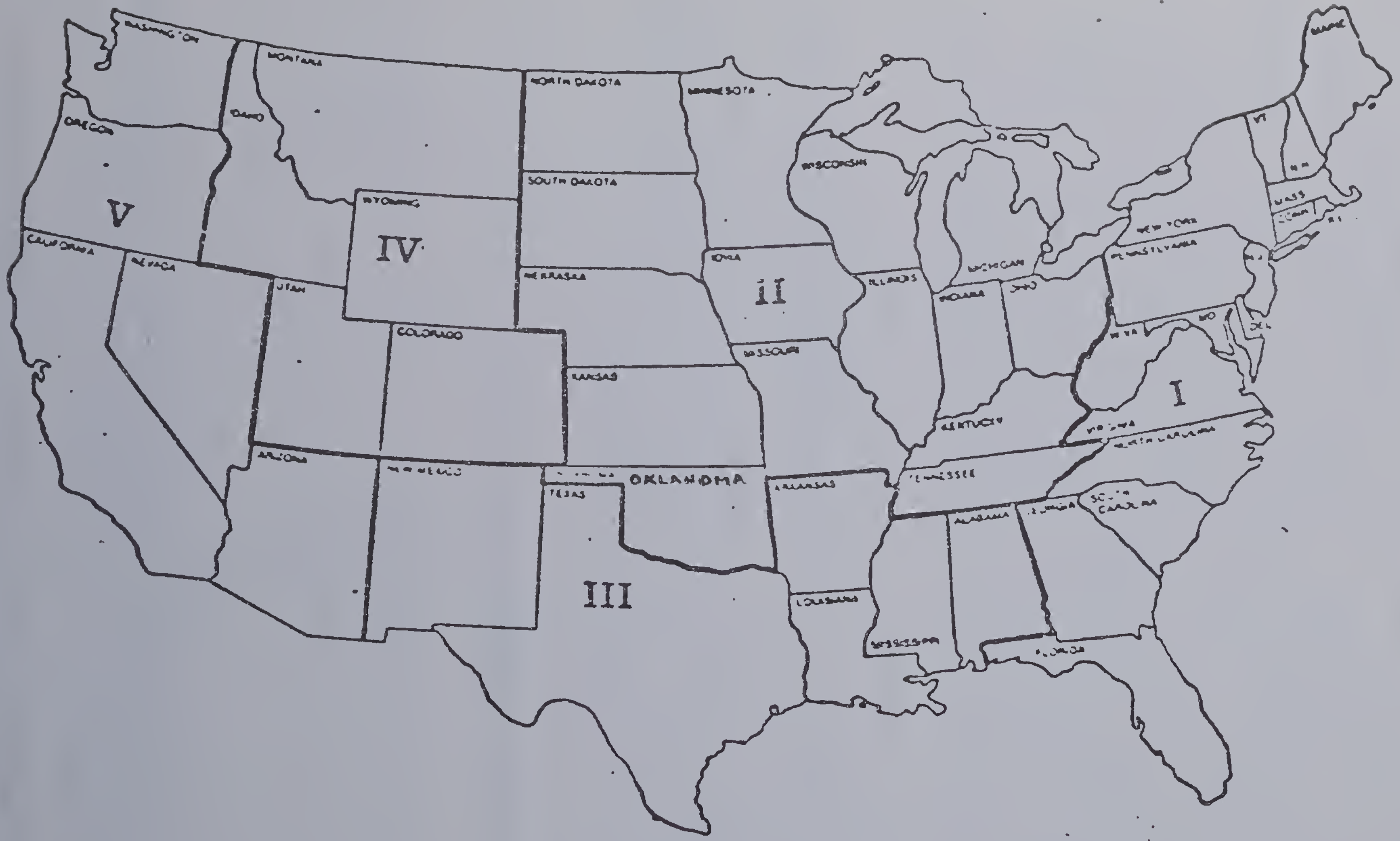
Projected Oil Imports (Million b/d)

	1975	1980	1985
Case I	7.2	5.8	3.6
Case II	7.4	7.5	8.7
Case III	8.5	10.6	13.5
Case IV	9.7	16.4	19.2

(Cases are based on varying economic conditions and oil and gas finding rates. These projections were made before the October 1973 oil embargo and the President's announcement of the goal of U.S. energy self-sufficiency).

(Source: National Petroleum Council, p. 272-4, 1972)

Petroleum Administration for Defense (PAD) Districts



Alaska and Hawaii are included in District V.

Increased imports will necessitate expansion of U.S. port capacity. An important factor is the size of oil tankers coming into port. Very Large Crude Carriers (VLCC's) ranging from 250,000 DWT to 425,000 DWT (dead weight ton, the cargo carrying capacity in long tons, 2240 lbs.) achieve reductions in unit transportation costs and in ship traffic (at a constant cargo carried). However, the U.S. does not have ports capable of handling tankers larger than 100,000 DWT. Such ports or alternate facilities must be developed in order to handle increased imports of petroleum.

Petroleum imports have a negative effect on U.S. balance of payments. This impact is affected by: type of import, e.g., crude or refined; price of imported oil; the exporting countries' level of imports from the U.S.; amount of U.S. capital invested in related facilities in the exporting country, and the amount of goods and services used in the exporting country for these facilities; and the nationality of vessels carrying the oil.

The primary environmental hazard of oil imports is the possibility of oil spills due to intentional discharge (mostly from cleaning operations), accidental discharge, and tanker casualties. A small percentage of the total volume of transported oil is spilled due to tanker accidents. Although a single incident can potentially be disastrous to marine organisms, low-level chronic pollution possibly causes greater and longer term environmental damage.

2. Increased Onshore Oil and Gas Production

Conventional oil and gas production from the lower 48 states has not been able to meet rapidly growing demand. Future U.S. gas supplies will be supplemented in increasing quantities by overland pipeline imports, liquefied natural gas, and substitute natural gas.

Forecasts of natural gas supplies are presented below for four cases.

Future Natural Gas from Conventional Sources

(Trillion cf)

Case I

	1971	1975	1980	1985	1990
Lower 48 states onshore	18.6	17.17	14.1	11.0	8.3
Alaska	.1	.2	.2	.3	.3
Gas from stimulation of low permeability reservoirs *	.0	.0	.0	.0	.0
Total	18.7	17.9	14.3	11.3	8.6

*Includes those low permeability reservoirs which contain gas that is not commercially producible under current prices and technology.

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Case II (Trillion cf)

	1975	1980	1985	1990
Lower 48 states onshore	17.9	14.7	12.0	9.6
Alaska	.2	.2	1.9	2.7
Gas from stimulation of low permeability reservoirs	.0	.1	.5	1.0
Total	18.1	15.0	14.4	13.3

Case III (Trillion cf)

	1975	1980	1985	1990
Lower 48 states onshore	18.0	15.3	13.3	11.3
Alaska	.2	1.9	2.5	3.8
Gas from stimulation of low permeability reservoirs	.0	.5	1.0	1.5
Total	18.2	17.7	16.8	16.6

Case IV (Trillion cf)

	1975	1980	1985	1990
Lower 48 states onshore	18.0	15.6	14.1	12.5
Alaska	.2	2.2	3.1	5.7
Gas from stimulation of low permeability reservoirs	.0	1.2	3.0	4.6
Total	18.2	19.0	20.2	22.8

Case I assumes little change in the current situation.
Cases II and III are intermediate cases.
Case IV is the maximum supply case.

(Source: Federal Power Commission, p. 4-5, 1974)

Conventional gas supplies are expected to decline despite U.S. estimated gas potential. The development of new reserves required to meet gas demand will depend on continued development of onshore areas and development of commercially viable nuclear stimulation or massive hydraulic fracturing to produce natural gas from low permeability reservoirs.

A forecast of U.S. petroleum supply is given below.

U.S. Domestic Petroleum Supply from Conventional Sources*

	1971	1975	1980	1985	2000
Lower 48 - million bbls.	4117	4000	3740	3345	2200
million b/d	11.3	11.0	10.2	9.2	6.0
Alaska - million barrels	-	-	550	730	1295
million b/d	-	-	1.5	2.0	3.5

* Includes offshore production.
(Source: U.S. Department of the Interior, p. 31, 1972)

Environmental impacts of oil and gas development include land subsidence; soil sterilization due to oil, brines, and waste materials released by blowouts, equipment failures, and human error; disturbance of land by building roads and structures; and pollution of ground and surface water due to poor well construction and spills.

3. Increased Nuclear Power

The Atomic Energy Commission (February 1974) has forecast nuclear power growth under four cases, intended to predict a range within which future development is likely to be. Basic to all the forecasts is the assumption that economic and environmental benefits of nuclear power are such that it becomes the dominant technology for base load electric power generation at the end of the century. In the near term, the four cases reflect different assumptions of demand for electrical energy and ability of the industry to meet schedule for commercial operation of nuclear and fossil fuel plants.

Case A, the lowest forecast, assumes that delays in bringing plants on line will continue. Project time would be about 2 years for planning and design, license application and environmental report preparation, two years for construction permit approval, and six years for construction and start-up.

Case B assumes some improvement over recent construction and regulation delays. Project times would average eight years, with 15 month for construction permits, and 5½ years for construction and start-up.

Case C assumes further improvements in construction performance and regulatory processes. Project times would be about six years with one year for design and planning, license application preparation and environmental review and five years for construction and start-up.

Case D assumes a general reduction for growth rate of electricity use, which is realized in the near term by cutbacks in oil and gas fired plants. Nuclear project times would be eight years, as in Case B.

In order to give a meaningful range, near term forecasts of high capacity were tied to long term forecasts of high future demands, and similarly near term forecasts of low capacity were tied to long term forecasts of low demand. The Census Bureau's Series E population projection was used, coupled with alternative paths of economic growth and energy development.

The types of reactors that will comprise U.S. nuclear capacity are shown for each case. The fast breeder reactor (FBR) is expected to be in commercial use starting about 1988. The high temperature gas reactor (HTGR) is expected to enter the nuclear market at about 10 percent of additions in the early 1980's, and 15 percent from the late 1980's through 2000. The remaining nuclear additions are expected to be light water reactors (LWR's), with one-third boiling water reactor (BWR's) and two-thirds presurized water reactors (PWR's).

RECASTS OF ENERGY CONSUMPTION AND ELECTRIC GENERATING CAPACITY IN THE UNITED STATES

	Case	1960	1970	1975	1980	1985	1990	1995	2000
rgy Consumed, Million Btu per pita	A	247.	329.	357.	378.	401.	429.	462.	499.
	B	247.	329.	372.	428.	485.	558.	635.	719.
	C	247.	329.	376.	434.	497.	569.	650.	737.
	D	247.	329.	364.	399.	438.	494.	563.	642.
tion for Electricity Generation	A	.18	.24	.29	.33	.37	.42	.46	.51
	B	.18	.24	.29	.31	.34	.40	.45	.50
	C	.18	.24	.29	.34	.38	.43	.49	.54
	D	.18	.24	.29	.32	.36	.41	.46	.50
ngy Consumed for Electricity Generation, Million Btu per Capita	A	44.2	80.3	105.	125.	148.	180.	215.	253.
	B	44.2	80.3	107.	133.	166.	220.	283.	357.
	C	44.2	80.3	111.	147.	189.	246.	316.	399.
	D	44.2	80.3	107.	129.	156.	201.	257.	324.
parent Capacity Factor	A B C D	.49	.52	.50	.49	.50	.51	.51	.52
e Rate, Thousands Btu per kwh	A B C D	10.7	10.5	10.2	10.1	10.0	9.8	9.8	9.6
o Electric Generating Capacity per pita, kw per Capita	A	.97	1.67	2.36	2.88	3.33	4.14	4.90	5.81
	B	.97	1.67	2.41	3.07	3.76	5.07	6.45	8.19
	C	.97	1.67	2.50	3.38	4.25	5.67	7.27	9.22
	D	.97	1.67	2.41	2.99	3.52	4.62	5.85	7.45
o Electric Generating Capacity, ousands of MW	A	168.	341.	510.	655.	800.	1040.	1280.	1575.
	B	168.	341.	520.	700.	903.	1275.	1685.	2220.
	C	168.	341.	540.	770.	1020.	1425.	1900.	2500.
	D	168.	341.	520.	680.	865.	1160.	1530.	2020.
o Nuclear Generating Capacity, ousands of MW	A	.02	5.8	43.3	85.0	230.9	410.	620.	850.
	B	.02	5.8	47.3	102.1	260.0	500.	820.	1200.
	C	.02	5.8	52.0	112.4	275.0	575.	960.	1400.
	D	.02	5.8	47.3	102.1	250.0	475.	760.	1090.

urce: U.S. Atomic Energy Commission, p.6, February 1974)

FORECASTS OF U.S. NUCLEAR POWER GROWTH

(Thousands of Electrical Megawatts) *

Calendar Year	Case A		Case B		Case C		Case D	
	Additions	Cumulated	Additions	Cumulated	Additions	Cumulated	Additions	Cumulated
1974	3.4	27.5	8.7	32.8	18.1	42.1	8.7	32.8
1975	15.9	43.3	14.5	47.3	9.8	52.0	14.5	47.3
1976	9.8	53.1	7.0	54.3	8.5	60.5	7.0	54.3
1977	7.4	60.5	7.0	61.3	4.9	65.4	7.0	61.3
1978	4.0	64.5	8.3	69.7	7.4	72.7	8.3	69.7
1979	7.9	71.7	11.8	80.7	14.6	86.5	11.8	80.7
1980	13.4	85.0	21.5	102.1	26.0	112.4	21.5	102.1
1981	29.2	114.2	32.2	134.3	32.0	144.4	24.9	127.
1982	28.4	142.6	28.1	162.4	30.1	174.4	28.	155.
1983	31.2	173.8	25.8	188.2	34.6	209.0	29.	184.
1984	31.2	205.0	34.7	222.9	31.	240.	32.	216.
1985	25.9	230.9	37.1	260.0	35.	275.	34.	250.
1986	34.1	265.	42.	302.	48.	323.	38.	288.
1987	35.	300.	43.	345.	57.	380.	43.	331.
1988	35.	335.	48.	393.	60.	440.	44.	375.
1989	37.	372.	52.	445.	65.	505.	48.	423.
1990	38.	410.	55.	500.	70.	575.	52.	475.
1991	42.	452.	60.	560.	72.	647.	52.	527.
1992	43.	495.	61.	621.	74.	721.	56.	583.
1993	43.	538.	65.	686.	77.	798.	57.	640.
1994	42.	580.	66.	752.	80.	878.	60.	700.
1995	40.	620.	68.	820.	82.	960.	60.	760.
1996	45.	665.	69.	889.	85.	1045.	63.	823.
1997	46.	711.	74.	963.	87.	1132.	65.	888.
1998	48.	759.	75.	1038.	89.	1221.	65.	953.
1999	46.	805.	80.	1118.	90.	1311.	67.	1020.
2000	45.	850.	82.	1200.	89.	1400.	70.	1090.

* Rounding anomalies and plant retirements affect cumulated data.

(Source: U.S. Atomic Energy Commission, p. 8, February 1974)

U.S. Nuclear Power Capacity by Reactor Type (MW)

C:e A

	Percent of Total Capacity					Total Capacity
	HTGR	PWR	BWR	Other	FBR	
1!3	0.2%	57.3%	39.4%	3.7	---	24,100
1!5	0.8%	61.7%	35.8%	1.8	---	43,300
1!0	0.4%	64.7%	34.9%	----	---	85,000
.!5	3.9%	64.8%	31.1%	----	0.2%	230,000
1!0	8.2%	61.5%	29.2%	----	1.1%	410,000
1!5	9.7%	56.8%	27.4%	----	6.1%	620,000
2(0	9.6%	51.0%	24.8%	----	14.6%	849,800

Asumes Plutonium recycle, 75% capacity factor.

HTR high temperature gas reactors
PW pressurized water reactor
BW boiling water reactor
FB fast breeder reactor

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Case B

	Percent of Total Capacity					Total Capacity
	HTGR	PWR	BWR	Other	FBR	
1973	0.2%	57.3%	39.4%	3.3%	---	24,100
1975	0.7%	60.5%	37.0%	1.7%	---	47,300
1980	1.1%	66.4%	32.5%	----	---	102,100
1985	4.7%	64.5%	30.7%	----	0.2%	260,000
1990	9.4%	60.7%	29.0%	----	0.9%	500,000
1995	10.6%	55.5%	26.9%	----	6.9%	820,000
2000	10.2%	49.2%	24.0%	----	16.7%	1,200,000

Case C

	Percent of Total Capacity					Total Capacity
	HTGR	PWR	BWR	Other	FBR	
1973	0.2%	57.3%	39.4%	3.3%	---	24,100
1975	0.6%	64.2%	33.7%	1.5%	---	52,000
1980	1.0%	68.3%	30.4%	----	0.4%	112,400
1985	5.2%	63.8%	30.8%	----	0.1%	275,000
1990	10.0%	60.0%	29.1%	----	0.9%	575,000
1995	11.0%	54.9%	26.9%	----	7.1%	960,000
2000	10.5%	48.9%	24.0%	----	16.6%	1,400,000

Case D

	Percent of Total Capacity					Total Capacity
	HTGR	PWR	BWR	Other	FBR	
1973	0.2%	57.3%	39.4%	3.3%	---	24,100
1975	0.7%	60.5%	37.0%	1.7%	---	47,300
1980	1.1%	66.4%	32.5%	----	---	102,100
1985	4.2%	64.6%	31.0%	----	0.2%	250,000
1990	9.1%	60.8%	29.1%	----	0.9%	475,000
1995	10.4%	55.8%	27.1%	----	6.7%	760,000
2000	10.1%	49.7%	24.2%	----	16.0%	1,090,000

(Source: U.S. Atomic Energy Commission, February 1974)

Although nuclear plants do not emit particulates or gaseous pollutants from combustion, several unique environmental problems arise. Some radioactivity in the form of radiation, airborne radioactivity, and radioactive liquids, is released to the environme Although the amount released is very small and potential exposure has been shown to be less than the average level of natural radiation exposure, special precautions are required to control these emissions. The possible release of radioactivity as a result of an accident must be anticipated in the design of the plant and its emergency systems. Malfunction of the emergency core cooling system has been of particular concern.

Nuclear plants use essentially the same cooling process as fossil fuel plants and thus share the problem of heat dissipation from cooling water. However, light water reactors require larger amounts of cooling water and discharge greater amounts of waste heat to the water than comparably sized fossil fuel plants. The effects of thermal discharges may be beneficial in some cases. Adverse effects can be mitigated by use of cooling ponds or cooling towers.

Low level radioactive wastes from normal operation of a nuclear plant must be collected, placed in protective containers, and shipped to an AEC storage site and buried. High level wastes created within the fuel elements remain there until the fuel is spent. They are then isolated in a fuel reprocessing plant and stored in liquid or solid form at AEC facilities.

4. Increased Use of Coal

The U.S. has huge reserves of coal of all kinds and qualities, well dispersed throughout the Nation. Recoverable reserves of coal include at least 28 billion tons of 1 percent or less sulfur content in the East and 70 billion tons in the West. Of the Eastern coast, 26 billion tons is suited to underground mining and 2 billion to strip mining. Of the Western coal, 40 billion tons is suited to underground mining and 30 billion tons to strip mining. (U.S. Department of the Interior, p. 13, 1974).

The basic problem of coal supply is not ready reserves but rather limitations of producing capacity. Various factors have discouraged the investments needed to develop large new mines. These factors include: large volume consumers are reluctant to secure long-term contracts needed to assure markets over the 20 to 30 year life of such new mines; uncertainties about future competitive positions of different energy sources, for example nuclear power and oil imports, over such time periods; environmental regulations; and potential for significant technological changes affecting coal.

The following table shows projected coal supply by region. These projections show substantial increases in Western coal production and slower increases in Eastern coal production. Western coal shipments eastward will likely be substantial but restricted to a degree by high transportation costs and lower heat content than Eastern coal. Advances in sulfur removal technology will also affect the competitive positions and development of Western vis a vis Eastern coal.

Coal Supply by Regions (in millions of short tons)

1975	
Eastern	427
Central	167
Western	76
Total U.S.	670
1977	
Eastern	455
Central	176
Western	96
Total U.S.	727
1980	
Eastern	499
Central	206
Western	134
Total U.S.	839

(Source: U.S. Department of the Interior, pp. 23-25, 1974)

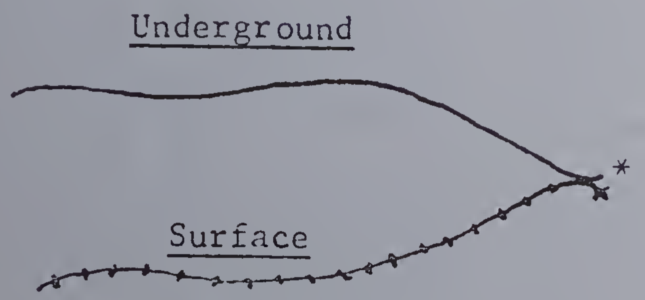
In the immediate future, deterrents to achieving air quality objectives are inadequate capacity to mine enough low sulfur coal, lagging development and installation of processes for the removal of pollutants from stack gas emissions, and difficulties in developing technologie for large scale removal of organic sulfur from most coals.

Future coal production will be influenced by possible surface mining regulations. The number of underground mines has steadily declined since 1965, while the number of surface mines (strip and auger) increased, and in 1971 surpassed the number of underground mines. Costs of underground coal are substantially higher than surface mined coal, and lead times to expand production are longer. New strip mining regulations would change the balance, in terms of cost and production, between surface and underground mining.

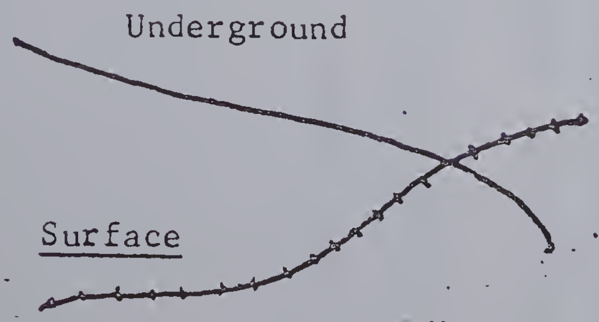
The following tables show number of and production from underground and surface mines.

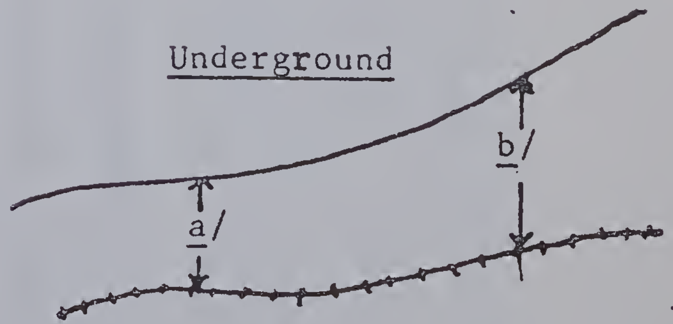
Bituminous Coal and Lignite
Production, Number of Mines, and Value f.o.b. Mines
1965 - 1972

Year	Production (million tons)				Number of Mines				Average value per ton, f.o.b. mines			
	Underground	Strip	Auger	Total	Underground	Strip	Auger	Total	Underground	Strip	Auger	Total
1965	333	165	14	512	5,280	1,541	407	7,228	$4.93	$3.57	$3.36	$4.44
1966	339	180	15	534	4,741	1,572	436	6,749	5.05	3.64	3.58	4.54
1967	349	187	16	552	3,908	1,507	458	5,873	5.18	3.68	3.59	4.62
1968	344	186	15	545	3,381	1,492	454	5,327	5.22	3.75	3.53	4.67
1969	347	197	16	560	3,097	1,551	470	5,118	5.62	3.98	3.81	4.99
1970	339	244	20	603	2,939	2,103	559	5,601	7.40	4.69	6.08	6.26
1971	276	259	17	552	2,268	2,290	591	5,149	8.87	5.19	6.57	7.07
1972	304	276	15	595	1,996	2,309	574	4,879	9.70	5.48	6.54	7.66



* 50 percent each in 1971
49 percent surface, 51 percent underground in 1972





a/ Average spread, 1965 - 1969: $1.50/ton
b/ Spread, 1972: 4.22/ton

underground in 1972

b/ Spread, 1972: 4.22/ton

Production of Bituminous Coal and Lignite in Eastern and Western States

(In thousand short tons)

State	1970				1972			
	Underground	Strip	Auger	Total	Underground	Strip	Auger	Total
East of the Mississippi River								
Alabama	9,078	11,339	143	20,560	7,588	13,177	49	20,814
Illinois	32,093	33,026	-----	65,119	31,721	33,802	-----	65,523
Indiana	2,094	20,169	-----	22,263	1,446	24,503	-----	25,949
Kentucky	62,610	52,836	9,859	125,305	56,494	55,776	8,917	121,187
Maryland	238	1,266	111	1,615	141	1,435	65	1,640
Ohio	18,111	35,818	1,422	55,351	16,269	34,077	621	50,967
Pennsylvania	55,382	24,447	661	80,491	49,133	26,264	542	75,939
Tennessee	4,350	3,729	157	8,237	5,866	5,113	281	11,260
Virginia	28,018	5,103	1,895	35,016	23,993	7,935	2,100	34,028
West Virginia	116,414	21,885	5,772	144,072	101,662	19,101	2,979	123,743
Total 1/	328,388	209,618	20,020	558,029	294,313	221,183	15,554	531,050
West of the Mississippi River								
Alaska	-----	549	-----	549	-----	668	-----	668
Arizona	-----	132	-----	132	-----	2,954	-----	2,954
Arkansas	51	217	-----	268	8	420	-----	428
Colorado	3,858	2,167	-----	6,025	3,070	2,452	-----	5,522
Iowa	423	565	-----	987	352	499	-----	851
Kansas	-----	1,627	-----	1,627	-----	1,227	-----	1,227
Missouri	-----	4,447	-----	4,447	-----	4,551	-----	4,551
Montana	28	3,419	-----	3,447	17	8,204	-----	8,221
New Mexico	938	6,423	-----	7,361	1,014	7,235	-----	8,248
North Dakota	-----	5,639	-----	5,639	-----	6,632	-----	6,632
Oklahoma	219	2,201	7	2,427	88	2,536	-----	2,624
Texas	-----	NA	-----	NA	-----	4,045	-----	4,045
Utah	4,733	-----	-----	4,733	4,770	32	-----	4,802
Washington	32	5	-----	37	29	2,606	-----	2,635
Wyoming	118	7,105	-----	7,222	442	10,487	-----	10,928
Total 1/	10,400	34,496	7	44,901	9,790	54,548	-----	64,336
Total U.S. 1/	338,788	244,117	20,027	602,932	304,103	275,730	15,554	595,386

NA Not available.

1/ Data may not add to totals shown because of independent rounding.

SOURCE: Bureau of Mines annual reports.

(Source: U.S. Department of the Interior, p. 177, 1974)

The primary environmental impacts of coal begin with coal mining. Underground mining may cause land subsidence and poses greater hazards to health and safety of miners. Strip mining and open pit mining disrupt large surface areas, causing destruction of top soil, wildlife habitats, and vegetation. Revegetation is more difficult in dry areas, including those where much of the Western coal reserves are found. Large volumes of mine wastes require disposal. Water quality problems may arise from damage to the ground water regime, acid mine drainage, and increased run off and sediment loads in streams. Stripping increases the dust in the air. Combustion of coal, especially high sulfur coal, releases particulates and gaseous pollutants. Technology to control these pollutants is not completely developed. Desulfurization of high sulfur coal before use and sulfur removal during combustion remove only limited amounts of sulfur. Much effort is now being directed toward development of processes to remove sulfur from flue gases or other process gases before discharging them to the atmosphere.

Increased Hydroelectric Power

Thirty to forty years ago, hydroelectric power supplied as much as 30 percent of the electric energy produced in the U. S. Hydroelectric power has increased steadily but at a rate slower than the growth rate of thermal plants. Today, conventional hydroelectric plants supply about 15 percent of U.S. electric generating capacity and electric energy production.

The following tables show current and projected hydropower development, both conventional and pumped storage.

Nearly one-half of conventional capacity and over one-half of the generation is in the Pacific division (Washington, Oregon, and California). About 90 percent of the conventional capacity now under development is in the Pacific division. About one-third of the capacity in the construction stage is at undeveloped sites and the remainder is in additions to existing developments.

In addition to capacity now under construction, about two-thirds of conventional capacity projected for development through 1983 would be in the Pacific division. About 20 percent would be at new sites and the remainder additions to existing developments.

Over sixty percent of conventional capacity identified for possible development by 1993 would be in Washington, Oregon, Idaho, and Montana. Over one-half would be at new sites.

Conventional hydroelectric development in the contiguous U.S. is summarized below:

	Installed Capacity MW	Average Annual Generation billion KWh
Existing as of May 1974	54,885	259.6
Hydro-development underway	6,878	14.8
Other hydro projected through 1983	4,620	8.2
Total as of 1983	66,383	282.6
Additional hydro possible through 1993	12,204	25.9
Total as of 1993	78,587	308.5

(Source: Federal Power Commission, May 1974)

Conventional hydroelectric projects under construction, planned, and possible of development in the next two decades could increase the developed hydroelectric capacity by more than 40 percent and the annual generation by 20 percent. At that time, conventional hydroelectric projects could account for only five percent of the capacity and about four percent of the annual generation required to meet the electric loads predicted for 1993 by the regional electric reliability councils. (Federal Power Commission, p. 3, May 1974).

CONVENTIONAL HYDROELECTRIC POWER IN THE
UNDER CONSTRUCTION AS OF MAY 1974
BY GEOGRAPHIC DIVISIONS 1/

Table 1

Geographic Divisions 2/	Developed: No. of Plants	Developed: Installed Capacity MW	Developed: Average Annual Generation 1000 MWh	Under Construction: No. of Plants	Under Construction: Installed Capacity MW	Under Construction: Average Annual Generation 1000 MWh
1. New England	235	1,490.3	5,966.5	2	28.8	104.0
2. Middle Atlantic	166	4,246.2	25,554.5	0	0.0	0.0
3. East North Central	216	935.1	4,413.0	1	30.8	130.0
4. West North Central	79	2,769.4	10,266.7	2	27.0	287.6
5. South Atlantic	167	5,467.4	15,365.2	3	431.4	427.0
6. East South Central	54	5,373.5	21,454.7	2	129.0	398.6
7. West South Central	41	2,257.4	6,430.8	0	0.0	0.0
8. Mountain	180	6,665.0	29,573.1	2	48.0	195.5
9. Pacific	290	25,681.1	140,581.4	10	6,183.3	13,212.5
Total	1,428	54,885.4	259,605.9	22	6,873.3	14,755.2

1/ Data from FPC inventory of hydroelectric power resources. The only new capacity installed during the period January through April 1974, was 33,333 kW with annual generation of 157,000 MWh at Cordell Hull in the East South Central Division and 20,000 kW with annual generation of 85,800 MWh at Ozark in the West South Central Division.

2/ Geographic divisions:
1. Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut.
2. New York, New Jersey, Pennsylvania.
3. Ohio, Indiana, Illinois, Michigan, Wisconsin.
4. Minnesota, Iowa, Missouri, North Dakota, South Dakota, Nebraska, Kansas.
5. Delaware, Maryland, District of Columbia, Virginia, West Virginia, North Carolina, South Carolina, Georgia, Florida.
6. Kentucky, Tennessee, Alabama, Mississippi.
7. Arkansas, Louisiana, Oklahoma, Texas.
8. Montana, Idaho, Wyoming, Colorado, New Mexico, Arizona, Utah, Nevada.
9. Washington, Oregon, California.

(Source: Federal Power Commission, May 1974)

Conventional Hydroelectric Projects in the Contiguous U.S. Not Under Construction but Projected for Development by 1983 (As of May 1974)

State	No. Sites	Installed Capacity MW	Average Annual Generation 1000 MWh
Georgia	1	300.0	467.0
	2	167.0 A	90.0
Alabama	1	135.0	164.9
	2	140.0 A	134.0
Virginia	1	0.0 A*	34.0
	1	200.0 *	215.0
Ohio	1	40.0	300.0
Washington	1	108.0 A*	200.0
	7	2619.5 A	4719.5
Oregon	1	540.8 A	1,160.0
Idaho	1	10.0 a	37.0
Montana	2	175.7 A	220.0
Utah	1	50.4	180.0
	3	133.5	319.5
New Plants	(8)	868.9	1,683.4
Plant Additions	(17)	3,751.0	6,557.5
Total	(25)	4,619.9	8,240.9

A Addition to existing plant

a Addition to a plant for which the initial installation is presently underway.

* Reversible pumped-storage capacity also planned at the site.

(Source: Federal Power Commission, May 1974)

Other Conventional Hydroelectric Projects in the Contiguous U.S. Possible of Development by 1993 (As of May 1974)

State	No. Sites	Installed Capacity MW	Average Annual Generation - 1000 MWh
Maine	1	830.0	1,154.0
Georgia	2	102.0 A	126.0
	1	35.0 a	68.0
	1	100.0 *	160.0
Kentucky	1	108.0	280.0
Arkansas	2	125.0 A	108.6
Texas	1	105.0 A	70.0
W. Virginia	1	180.0	447.0
Pennsylvania	1	120.0 *	244.0
Montana	1	160.0 A	0.0
N. Dakota	1	240.0 A	0.0
S. Dakota	3	771.0 A	0.0
Nebraska	1	33.3 A	0.0
Washington	5	1,832.4 A	4,725.5
	1	110.0	418.0
Oregon	3	598.0 A	387.5
	2	1,530.0	2,966.5
California	3	423.5	1,666.0
Idaho	4	1,000.2 A	417.0
	5	1,315.0	4,932.5
Montana	3	490.0	1,725.0
	1	315.0 a	650.0
Wyoming	1	125.2	510.0
24 other new sites with individual capacity from 25 to 100 MW, and one developed site with 35.0 MW additional capacity		1,555.6	4,826.2
New Sites	44	6,802.3	19,159.2
Plant Additions	26	5,401.9	6,722.6
Total	70	12,204.2	25,881.8

Addition to existing plant.

Addition to a plant for which the initial installation is presently underway.

Reversible pumped-storage capacity also planned at the site.

Source: Federal Power Commission, May 1974)

There is a large undeveloped conventional hydroelectric potential in Alaska, amounting to about 32,500 MW of capacity with an average annual generation of some 172 billion kilowatt hours. Over seventy favorable sites have been identified in inventory studies. The following table lists 15 key projects which appear to have the greatest likelihood of near future developments, and those additional projects that appear to have the greatest potential in terms of long range State and national needs.

Key Hydroelectric Resources of Alaska

Project	Stream	Annual Firm Energy KWH x 10^6
Agashashok	Noatak River	820
Holy Cross	Yukon River	12,300
Ruby	Yukon River	6,400
Rampart	Yukon River	34,200
Porcupine	Porcupine River	2,320
Woodchopper	Yukon River	14,200
Yukon-Taiya	Yukon River	21,300 1/
Crooked Creek	Kuskokwim River	9,400
Chakachamna	Chakachatna River	1,600
Devil Canyon) 2/ Watana) Vee) : Denali)	Susitna River	7,000
Bradley Lake 3/	Bradley River	368
Wood Canyon	Copper River	21,900

(Source: Federal Power Commission, p. 59, May 1974a)

1/ Development of Yukon-Taiya would diminish energy potential of downstream sites on the Yukon River.
2/ Four units of Upper Susitna Project.
3/ Authorized Project.

The limited number of favorable sites for conventional hydroelectric development has encouraged the construction of pumped storage projects for peak-load use. The cost of pumping energy amounts to about three kilowatt-hours for each two kilowatt-hours generated. However, because pumping occurs during off-peak hours and uses more efficient plants than those that would otherwise generate peak energy, there may be little increase in system fuel use due to pumped storage installations.

In contrast to conventional hydroelectric capacity and potential, over 80 percent of pumped storage capacity, developed and underway, is in the central and eastern areas of the country. One-third of such capacity is located in the Middle Atlantic States.

Construction of a hydroelectric dam represents an irretrievable commitment of the land resources beneath the dam and the lake. Inundation of the land eliminates wildlife habitat and precludes other uses such as agriculture, mining, and free-flowing river recreation. Some increase in erosion during construction and operation will occur.

Hydroelectric projects use a renewable resource, do not directly cause air pollution, and offer some recreational activities. On the other hand, use of streams for power will displace some forms of recreational activities and eliminate vast areas for land uses. Water released from reservoirs during summer months may change the water temperature and lower the oxygen content of the river downstream, adversely affecting the indigenous fishery. Fluctuating flow releases for peak load operation may also adversely affect reservoir and downstream fisheries and recreation. The lack of satisfactory means of passing anadromous fish over high dams presently precludes development of some hydroelectric sites.

Fish may die if exposed to nitrogen supersaturated water. Nitrogen supersaturation results at a dam when excess river flow must be passed over the spillway. High nitrogen levels in the Columbia and Snake Rivers pose a threat to salmon and steelhead resources of these rivers.

6. Increased Energy Conservation*

In the short term, energy conservation offers the only option for matching energy requirements to available supply. Reliance on imported energy supplies poses high costs, both economic and political. Continued high rates of growth in energy demand must contend with eventual depletion of finite resources such as petroleum, natural gas, and uranium, and perhaps unacceptable environmental degradation. The goals of national self-sufficiency and conservation of natural resources are best achieved through energy conservation.

In the past, inexpensive and easily available energy has resulted in emphasis on initial costs rather than operating costs. Energy use has been of little economic importance in industrial, commercial, or government operations. The result has been thermally inefficient industrial processes, buildings in which energy use is almost impossible to control, and a disregard of energy use in transportation, urban development, and almost everything else.

Rate of introduction of energy conservation will depend largely on Government policies, removal of institutional constraints, promotion of incentives and regulations to induce conservation and investment in more efficient plant and processes, rate of retirement of existing structures, equipment, etc. and its replacement by more energy efficient elements, and prices of energy sources.

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* This discussion is largely taken from Energy Conservation Strategies, a report published by the Environmental Protection Agency. See the list of references at the end of this section.

The following discussion focuses on energy conservation potential in each of the three sectors: residential-commercial, industry, and transportation.

The residential and commercial sector accounted for about 55 percent of total electrical energy consumption in 1970, and about 34 percent of total energy consumption. Promising means of reducing energy demand in this sector include increasing insulation, increasing consumer awareness of energy saving alternatives, encouraging energy awareness in appliance choice and other decisions (as opposed to considering only initial cost), and controlling the quality of energy saving installation.

A study by the Oak Ridge National Laboratory (Moyers, 1971) shows substantial savings from increased insulation in this sector. Increasing energy costs increase the optimum amounts of insulation and potential energy and monetary savings. Even with a one third increase in the cost of insulation, positive savings are still possible in all regions, compared with current insulation practises.

Improper installation of insulation results in some increase in energy use. Enactment of regulations concerning quality of installation and quality of materials would discourage slipshod construction techniques and consequent energy losses due to improper insulation. However, such regulations would be difficult to enforce.

Modification of institutional barriers could also encourage energy saving techniques. For instance, Federal Housing Authority appraisals do not generally include storm windows or other energy saving investments in the appraised value. This exclusion keeps homeowners unaware of energy saving techniques and has encouraged a serious underinvestment in such options.

Industrial end use energy consumption accounted for about 42 percent of total energy consumption and 42 percent of total electrical energy consumption in 1970.

Energy conservation in the industrial sector involves producing materials in a more energy efficient way or choosing more energy efficient materials for use in final products. Conservation can be achieved by recycling selected materials rather than extracting them from raw mineral resources. For example, recycling copper scrap uses much less energy than producing copper from ores. Energy saving increases greatly when poorer grades of copper and titanium ores must be used.

Replacement of metals by others which require less energy to produce could reduce industrial energy consumption. The replacement of steel by aluminum in certain car parts has largely caused the sharp increase in energy used to produce automobiles. Reduction of aluminum content of cars by replacing aluminum with steel or by reducing total metal content of cars could foster energy conservation. Increasing use of plastics instead of natural materials generally causes increases in energy use. Replacement of aluminum by steel in construction of office buildings would reduce energy use, although the cost effectiveness depends on prices of the different options.

Energy conservation is also possible through investment in energy saving equipment such as heat wheels, insulation for vacuum furnaces, advanced heat-pipe technology, and known techniques for more efficient heat transfer and combustion.

Other energy conserving options for industry are:

changing temperature settings for both heating and cooling

replacing gas pilot lights with less energy intensive devices

shutting down or idling equipment at optimal holding temperatures whenever production is interrupted

rearranging schedules to utilize process equipment for continuous operations

adjusting combustion equipment for maximum fuel efficiency.

The transportation sector directly accounts for about one fourth of total U.S. energy use. Over 95 percent of this energy comes from petroleum. Energy conservation in this sector could be achieved through (1) reducing transportation demand, (2) shifting traffic to more energy efficient modes, (3) increasing energy efficiency of existing modes by technological change, better utilization of present technology, or improving vehicle load factors in present modes.

U.S. transportation is dominated by the least energy efficient modes. In the urban passenger sector, the lowest energy efficient mode, the automobile, predominates. Shifts toward mass transit, land use planning which takes energy into account, and increases in auto efficiency can increase efficiency in this sector.

In the inter-city passenger sector, the automobile and airplane, the lowest efficiency modes, prevail. The share of this market controlled by buses and railroad is declining. Reversing this decline and increasing auto efficiency would achieve greater energy efficiency in this sector.

Energy conservation strategies for the transportation sector include:

improving the competitive position of rail freight

improving energy efficiency of trucks

raising automobile operating costs

promoting use of carpools

increasing energy efficiency of autos through technology

improving mass transit facilities by improving existing systems, initiating new mass transit services, linking urban mass transit systems to intercity modes, expanding intercity high-speed rail services, and building fringe parking facilities

promoting use of fringe parking facilities

stressing transport energy efficiency in all urban planning

improving freight delivery efficiency by terminal centralization, containerization, computerized optimization

Energy conservation programs can have significant consequences. After President Nixon's Energy Message of June 29, 1973, the Federal Energy Reduction Program was begun. The first quarter of FY 74 saw a savings of energy use by the Federal Government of 20.8 percent, while the second quarter showed a savings of 26 percent over projected usage (six month average = 23.4%). This was a savings of 262,000 billion Btu's, the equivalent of 45 million barrels of oil. Some of this saving was due to a mild winter, but even during the oil crisis, an energy shortfall of 2.7 million barrels of oil a day was compensated for by the measures outlined above. In New England, energy consumption of residential heating oil was cut 15 percent, after adjusting for the warm weather. The ban on Sunday gasoline sales, the 55 mph speed limit the allocation of reduced amounts of gasoline, and the desire of people to overcome the problem by reduced driving all contributed to an approximately 20 percent reduction in gasoline consumption from projected usage. Recent newspaper reports indicate that gasoline consumption in the summer of 1974 was approximately the same as in 1973, a savings brought about by the continued 55 mph speed limit and by the impact on family economics of rising prices, especially the increased price of gasoline since the crisis.

Only the prominent measures familiar to everyone have been mentioned which allowed the Nation to deal with the Mideast oil embargo. There are numerous other complex measures which were imposed that are difficult to summarize and analyze. Energy conservation remains the critical area where an impact can be made on our demand-supply gap in energy resources.

Increased Pipeline Imports of Natural Gas

Imports of natural gas via pipeline have come largely from Canada, with small amounts from Mexico. In 1973 net pipeline imports from Canada were 1,012 Bcf, about 4.2 percent of total natural gas used in the U.S. These imports were about 45 percent of Canada's natural gas production. Natural gas pipeline imports from Mexico have not been a significant part of U.S. supply. In 1973, imports from Mexico were 1.6 Bcf. Almost 95 percent of pipeline gas imported in 1973 was delivered to interstate companies for transmission to major markets.

Projections of Natural Gas Pipeline Imports for Canada are shown below:

	Actual 1973	1975	1980	1985	1990
Case I	1.0	1.0	1.0	0.9	0.2
Case II	1.0	1.2	1.4	1.4	2.1
Case III	1.0	1.2	2.2	2.2	2.6
Case IV	1.0	1.2	2.9	2.9	3.7

Units - trillion cubic feet
(Source: Federal Power Commission, P. 45, 1974)

Case I represents the minimal case and shows volumes scheduled for export from Canada to the U.S. under current National Energy Board (NEB) and FPC authorizations. The case assumes no additional export authorizations granted through 1990.

Case II is a "conservative realistic" projection. It includes additional supplies under the following assumptions: (a) the NEB will authorize some additional exports from the traditional gas supply areas, (b) a large-diameter gas pipeline from the North Slope of Alaska through the Mackenzie Delta area will be completed and operating at capacity by 1984, and subsequent looping will increase the capacity by 1989. About half of the line's throughput will be from Alaska, (c) a large-diameter gas pipeline from the Arctic Islands will be completed and operating at capacity by 1990, and (d) by 1985 approximately 0.5 Tcf per year of the new supplies from the frontier areas will go to Canadian markets.

Case III is an "optimistic realistic" projection which has the additional element of a pipeline from the Atlantic Offshore. The assumptions are: (a) the NEB will authorize some additional exports on a short-term basis from the traditional gas supply areas until gas is available from the frontier areas, (b) the Alaska North Slope-Mackenzie Delta pipeline will be completed and operating at capacity by 1979, with subsequent increases in capacity in both 1985 and 1990, (c) the Arctic Islands line will be completed by 1984, and the maximum throughput will be increased by 1990, (d) a pipeline from the Canadian Eastern Offshore area to market areas in New England will be completed by 1980, and (e) by 1985 approximately 1 Tcf of gas per year from the frontier areas will go to Canadian markets.

Case IV is the most optimistic situation and is basically the same as Case III with the following exceptions: (a) the Alaska North Slope-Mackenzie Delta pipeline will be completed by 1978, (b) the Arctic Islands pipeline will be completed by 1979 with subsequent increases in capacity by both 1985 and 1990, and (c) substantial increases in capacity will be installed on the pipeline from the eastern offshore by 1985 and 1990.

In 1973, pipeline imports from Canada were delivered as follows:

West Coast Area (California, Oregon, Washington)	69 Percent (a little over half of this used in California)
Great Lakes market	26 percent
Montana	5 percent
New York and Vermont	less than 1 percent

Further imports from Alberta, if additional imports are authorized, will likely follow the established distribution pattern. Gas from Alaska's North Slope and Canada's Mackenzie Delta will likely come into the U.S. through Washington, Idaho, and Minnesota for ultimate use on the West coast and Great Lakes area. Gas from the Canadian Atlantic Offshore area will be delivered to New England. A gas pipeline from the Arctic Islands, depending on the route, could deliver gas directly to the northeastern states, or make gas available for the West coast and Great Lakes areas by displacement.

The proportion of imports coming into different regions could change considerably from present patterns. This will depend on the completion schedule of various proposed pipeline projects and regional demand for the Canadian gas.

Mexico is not likely to be a significant source of future imports because of its relatively small natural gas resource base, its policy of self-sufficiency in energy, and the small volume of current U.S. imports from Mexico. Imports from Mexico were of a local nature until 1957 and have declined since 1969. In 1973, they were only 1.6 Bcf, while exports to Mexico from the U.S. were 13 Bcf.

The environmental impacts of increasing gas imports derive mainly from the possible increased use of land for pipeline construction. Reliable estimates are not at hand relating carrying capacity of existing or planned pipelines to their actual load. To whatever degree that land is utilized for new pipelines to handle increased pipelines, this will determine the primary impact of this alternative. A less important impact is the risk of explosions and/or fires. The increased pipeline mileage or increased use of existing lines increases this risk, as does the increased use of tankers carrying LNG (liquefied natural gas).

8. Oil Shale Production

Oil shale occurs in large volumes throughout the U.S. and potentially could contribute significantly to U.S. energy supplies. The richest deposits are found in the Green River Formation in Colorado, Utah, and Wyoming. An estimated 80 percent of these resources are on Federal lands. These oil lands are sparsely settled and arid or semi-arid.

The main obstacles to development of oil shale in the U.S. have been abundant oil, gas, and coal at lower costs. As availability of these energy sources declines and prices rise, the economics of oil shale become more favorable.

From 1944 to 1956 the U.S. Department of the Interior conducted extensive research on mining and retorting oil shale and refining shale oil. For the past 10 years, private industry has operated prototype plants and experimental facilities. There has been no commercial production of oil from oil shale as yet.

The Department of the Interior has initiated a prototype oil shale leasing program to make available rich oil shale lands for development by private industry.

The major options for oil shale development are (1) mining (underground or surface) followed by surface processing of the oil shale, or

(2) in-situ (in place) processing. In-situ technology is important for eventual recovery of deeply buried oil shale but is less advanced than conventional processing. Projections of future oil shale capacity are given below.

Production of Shale Oil (thou. B/D)

	1975	1980	1985
Case I	0	150	750
Case II/III	0	100	400
Case IV	0	0	100

(Source: National Petroleum Council, p. 205, 1972)

Case I represents the maximum feasible production under non-emergency conditions and assumes shale oil prices adequate to encourage commercial development. Limitations on rate of development include availability of operating personnel, environmental restrictions, lack of supporting commerce and industry, and construction logistics. Cases II, III, and IV show slower rates of investment due to lack of incentive or need for time to demonstrate process feasibility.

The Department of the Interior has estimated maximum 1985 production of shale oil at one million barrels daily (U.S. Department of the Interior, vol. I, p. III-6, 1973). The rate of development will be determined by the logistics of plant construction, manpower constraints availability of water, and availability of oil shale lands of commercia potential.

Environmental problems related to the extraction of shale oil by conventional (as opposed to in-situ) retorting are magnified by the large volume of rock that would be processed in a commercial operation. A plant producing 100,000 b/d would probably mine about 130,000 tons of oil shale per day and would require disposal of a similar amount of spent shale. Surface disposal of the spent shale creates the problem of revegetation. Other problems are prevention of contamination of streams by a saline water encountered in mining or by leaching of salts from spent shale.

The Green River Formation area is sparsely settled and arid or semi-arid. Development of an oil shale industry would change existing land use patterns and create a major socio-economic impact in a region now without large scale industry. It would also disturb regional wildlife. The Colorado oil shale lands have some of the largest migratory deer and elk herds in the world.

Roads, mining plant sites, waste disposal areas and utility and pipeline corridors would disturb the vegetative cover of the land. The requirement of large amounts of waste water and the disposal of waste water with dissolved saline and organic compounds without degrading natural ground waters would place added stress on the scarce water resources of the region. Increased noise and a decline in air quality due to dust from mining and shale disposal and particulate and sulfur and nitrogen oxide emissions would accompany oil shale development.

9. Solar Energy

Solar energy utilizes a renewable resource and lacks many of the adverse environmental impacts associated with fossil fuel extraction, processing, and combustion. Under present technology, because solar energy is a diffuse, low intensity energy source, large scale solar energy collection complexes would require extensive land areas. In addition, because its intensity varies with time of day, weather, and season, solar energy must be stored or supplementary sources used during periods of little sun.

With few exceptions, all practical solar energy systems now in use are flat-plate collector systems. Materials, costs, and operational difficulties have prevented widespread application of focusing collect systems. Other potential applications are prohibitively expensive today. The silicon photovoltaic cell directly converts solar radiatio to electricity and has been used in outer space. Schemes for large scale production of electricity using solar cells in satellites or in ground installations await development of less expensive solar cells. Large scale power plants using collectors, located in desert areas, have also been suggested. Another potential application is use of thermal gradients to extract the solar energy stored in surface layers of the ocean. The difference in temperature between surface and cold deep water can be used to generate electricity. A proposed site is the southeastern coast of Florida, where the Gulf Stream passes.

Of the many applications of solar energy, few are cost competitive with other energy sources at the present time. The following table shows the state of development of various applications. Many conceptual applications have very high capital costs and would appear not to be cost competitive even in the long term. These shemes would require large government research and development funds and subsidies. However, extensive application for solar power does exist today in home heating and cooling and water heating using relatively inexpensive collectors. The main obstacles to such systems are not economic or technological but rather institutional. Small energy complexes for homes and buildings also could conceivably be profitable in the near future.

Among potential applications of solar energy, residential heating and cooling and solar water heating have the highest chance of success, especially in the near future. Space heating and cooling is not as advanced as water heating. Solar power potential is very favorable in California, Florida, and the Southwest.

A recent study analyzed solar heating and cooling of buildings (Westinghouse Electric Corporation, 1974). The principal findings are outlined below. The major demand for heating and cooling and hot water arises from residential buildings and three types of commercial buildings: offices, schools, and stores. The solar systems that would best meet this potential market are

Present Status of Solar Utilization Techniques

	Status					
Application	Research	Development	Systems test	Pilot plant demonstration	Prototype plant	Commercial
Thermal energy for buildings						
Water heating	X	X	X	X	X	X
Building heating	X	X	X			
Building cooling	X	X				
Combined system	X	X				
Renewable clean fuel sources						
Combustion of organic matter	X	X	X	X		
Bioconversion of organic materials to methane	X	X	X	X		
Pyrolysis of organic materials to gas, liquid, and solid fuels	X	X	X	X	X	
Chemical reduction of organic materials to oil	X	X	X			
Electric power generation						
Thermal conversion	X					
Photovoltaic						
Residential/commercial	X					
Ground central station	X					
Space central station	X					
Wind energy conversion	X	X	X			
Ocean thermal difference	X	X	X			

X indicates effort is underway but not necessarily complete.

(Source: National Science Foundation, National Aeronautics and Space Administration, p. 8, December 1972).

solar heating only, solar-assisted heat pump, solar heating and cooling (using absorption systems). None of these systems is economically competitive with oil or gas systems on a significant scale. The initial investment is appreciably greater for solar heating and cooling systems than for conventional systems in all regions.

Solar heating only systems can first become competitive for residences in the California region in 1975 to 1980. By 1980, these systems can become competitive, primarily for commercial and institutional structures, in several regions. Solar heating and cooling can become cost competitive in most regions by 1985-1990. The market for solar hot water heating only can grow in several regions of the U.S., creating a volume demand for solar collectors.

Solar energy economic feasibility will be largely determined by solar collector costs versus oil and gas prices. On the average, it will cost several thousand dollars more to equip a single-family residence with a solar system than with a conventional system. Retrofitting single-family residences is not likely to be economically feasible on a large scale. Retrofitting solar systems on larger buildings is approaching economic feasibility from a life cycle cost basis.

There is a gap between near term costs for solar systems and additional costs consumers would be willing to pay. Government programs and incentives will be required to close that gap (Westinghouse Electric Corporation, 1974).

10. Increased Liquefied Natural Gas (LNG) Imports

Liquefaction and transportation of foreign natural gas to the U.S. could contribute significantly to U.S. gas supply. Liquefied natural gas imports are of two types: short-term or long-term. Short-term imports are contracted for on a spot basis for delivery over a short period, at most a few years. Short-term imports in 1973 totalled less than 1 Bcf, and were from Algeria and Canada. Long-term imports are contracted for on a regular basis over a relatively long period, usually 20 to 25 years. Long-term imports from Algeria were about 3.1 Bcf in 1973 and were used for peak shaving supplies. There have been no long-term imports for base-load use in the U.S.

Long-term LNG projects are very capital intensive and require commitment of sufficient reserves for a project life of about 20 to 25 years. There are four phases in such projects: (1) foreign gas reserves, field development and pipeline facilities, (2) liquefaction plant and shipping terminal, (3) marine transportation, and (4) reviewing terminal, regasification plant, and pipeline facilities. Highly specialized ships capable of maintaining LNG at cryogenic temperatures are required.

Projections of LNG imports are shown below.

Projected Foreign LNG Imports
To the Contiguous United States
1975, 1980, 1985, 1990
(Trillion Cubic Feet)

	1975	1980	1985	1990
CASE I	*	.4	.4	.4
CASE II	.1	1.5	1.5	1.5
CASE III	.4	2.7	3.8	3.8
CASE IV	.4	3.2	3.8	4.7

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* 15 billion cubic feet.

(Source: Federal Power Commission, Vol.I, Chapter 10, p. 69, 1974)

Case I assumes that only those projects which are presently approved by the FPC will be completed.

Case II assumes only projects approved by or filed with the FPC will be completed.

Case III assumes projects approved by or filed with the FPC or noted in the trade press will be completed.

Case IV assumes all projects under Case III and others for which little data is available will be completed.

Future LNG imports will depend on Government polices, U.S. ability to compete on the world market for natural gas supplies, availability of capital, availability of LNG shipbuilding capacity, and amount of surplus world-wide gas reserves. It is not likely that foreign gas reserves or world-wide shipbuilding capacity will limit U. S. LNG imports. (Federal Power Commission, p. 71-80, 1974). However, development of baseload LNG projects in the U.S. will depend largely on Government policies and support (possibly loans and guarantees) and multinational planning and financing.

Most LNG delivery points for planned projects are on the East coast (Georgia, Maryland, Massachusetts, New Jersey, New York). A few projects plan West coast delivery (notably to California) and one a Texas delivery point.

Potential sources of LNG are Algeria, Australia, Abu Dhabi, Brunei, Ecuador, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Malaysia, New Zealand, Nigeria, Pakistan, Papua, Qatar, Saudi Arabia, Trinidad and Tobago, U.S.S.R., and Venezuela.

The environmental impacts of LNG imports are related to tankers; terminals, transfer and regasification facilities; and transportation of the gas. The primary hazard of handling LNG is the possibility of a fire or explosion during transportation, transfer, or storage.

Receiving and regasification facilities will require primary shoreline locations and dredging of channels. Regasification of LNG will release few pollutants to the air or water.

11. Synthetic Natural Gas and Oil Production

An alternative source which could provide significant volumes of domestic gas over the rest of the century is coal. The first coal gasification complexes are scheduled for northwestern New Mexico. In the long run, Montana, Wyoming, and North Dakota are expected to be major supply areas.

The main barrier to synthetic oil and gas development has been economics. Most processes have not been able to compete in cost with other energy sources. A great variety of processes have been developed, although none has yet reached commercial application. in the U.S. Research has been directed toward development of both low-Btu gas and pipeline quality gas. Utilities have shown much interest in integrated coal gasification-electricity generation systems using low-Btu gas.

A typical coal gasification plant of 250 MMcf/d capacity and average efficiency of 60 percent, will require an annual bituminous coal feedstock of 6 million tons. Capital requirements for such a plant have been estimated to be $260 to $305 million for an underground eastern site and $175 to $230 million for a surface mined western site. (Federal Power Commission, 1974).

The growth of the coal gasification industry depends on development of technology, water availability, and the productivity of the coal mining industry. Technology has been developed and is in commercial use in western Europe to produce low Btu value gas from coal through the Lurgi process. Processes to produce high Btu value pipeline quality gas have not been demonstrated on a commercial scale. Water availability is expected to be major consideration, especially in the Rocky Mountain region.

Projections of coal gasification capacity in the next decades are shown below.

Installed Capacity of Synthetic Gas From Coal
(Trillion cf/yr)

Case	1976	1980	1985
I	0.08	0.56	2.48
II/III	0.08	0.36	1.31
IV	-	0.18	0.54

Case I - maximum rate of buildup under special conditions and appropriate special policies.

Case II/III - Rapid but practical buildup rate.

Case IV - Minimum rate of buildup which can be foreseen on the basis of current economics.

(Source: National Petroleum Council, p. 167, 1972)

Synthetic natural gas can also be produced from liquid hydrocarbons. Technology for gasification of light liquid hydrocarbons(naphtha and natural gas liquids) has been available commercially for some time. The first U.S. high Btu liquid hydrocarbon gasification plant started operations in 1973. However, processes to gasify crude oil are in the early phase of commercial development.

Synthetic natural gas projects using light hydrocarbons as feedstock will be in direct competition with the petrochemical industry for feedstocks. Naphtha is presently in short supply because of limited domestic refinery output, shortages of crude petroleum, and high demand. Feedstock supplies for the Great Lakes gasification units will likely be natural gas liquids (NGL) from Canada. East Coast units will likely depend on domestic or imported naphtha or NGL.

The number of liquid hydrocarbon gasification plants built will depend largely on future crude and light hydrocarbon supplies. Production of SNG from liquid hydrocarbons will rely mostly on foreign sources of feedstocks. Natural gas liquids used for gasification are likely to come largely from Canada, with a small domestic contribution. Future potential suppliers of NGL are Africa and the Middle East.

Interior Department projections of SNG production from both coal and petroleum are shown below.

Synthetic Gas Production

	1980	1985	2000
Coal inputs			
Million tons	19	86	308
Trillion Btu	430	2000	7140
Petroleum inputs			
Million barrels	84	128	105
Trillion Btu	440	670	550
Total gas produced			
Billion cf	700	2000	5500
Trillion Btu	700	2000	5500
Conversion Efficiency* (Percent)	80	75	72

*The declining efficiency is due to larger percent of coal inputs relative to petroleum inputs. Assumed conversion efficiency is 70 percent for coal and 90 percent for petroleum.

(Source: U.S. Department of the Interior, p. 22, 1972)

Technology for liquefaction of coal has not yet been proven. The development of such technology will largely determine the rate of development of a coal liquefaction industry. Projections of coal liquefaction capacity are given below.

Buildup of Synthetic Liquids from Coal (MB/D)

	1977	1980	1985
Case I (maximum incentive)	30	80	680
Case II/III (moderate incentive)	-	-	-
Case IV (no incentive)	-	-	0

(Source: National Petroleum Council, p. 170, 1972)

Coal gasification and liquefaction share the environmental problems of coal mining and combustion. In addition, these processes must contend with water consumption and contamination, air pollution from components and particulates, and possible noise and site pollution. Impacts on air quality stem from sulfur oxides, hydrogen sulfide, nitrogen oxide, ash, and ammonia. Technology to control these emissions is under development.

12. Geothermal Energy Production

Geothermal energy is primarily heat energy from the interior of the earth. It may be generated by radioactive decay of elements such as uranium or thorium and friction due to tidal and crustal plate motions.

There are four major types of geothermal systems: hot water, vapor dominated, geopressured reservoirs, and hot dry rock systems.

Geothermal plants are smaller than conventional plants and require a greater amount of steam to generate the same amount of electricity. This is due to the fact that temperatures and pressures associated with geothermal areas are lower than those created at conventional power plants.

The greatest potential for geothermal energy in the U.S. is in the Rocky Mountain and Pacific regions; some potential exists in the Gulf Coastal Plain of Texas and Louisiana. The Geysers Field in California is the most extensively developed source of geothermal energy in the U.S. It has been producing power since 1960. Exploration efforts are also underway in the Imperial Valley, Salton Sea, Mono Lake, and Modoc County, California.

Within 20 years, geothermal energy may account for about 1 to 2 percent of total U.S. energy and about 5 percent of California's total energy consumption. The following table shows projected growth of geothermal power in California.

ESTIMATED GEOTHERMAL-POWER GROWTH IN CALIFORNIA*

	Megawatts				
	The Geysers	Imperial Valley	Other Areas	Total/ Year	Cummula ve Tota
Capacity at 12/31/71	184			184	18
Additional capacity:					
1972	106			106	29
1973	106	10		116	40
1974	106			106	51
1975	212			212	72
1976	212	200		412	1,13
1977	212	100	100	412	1,54
1978	212	100		312	1,86
1979	212	100	100	412	2,27
1980	212	100		312	2,58
1981	212	100	100	412	2,99
1982-1991				4,504	7,50

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* This estimate reflects only present development trend, not total sta potential.
(Source: Wilson, 1973)

A number of gases are associated with geothermal systems and may pose health and pollution problems. These gases include ammonia, boric acid, carbon dioxide, carbon monoxide, hydrogen sulfide, and others. However, adverse air quality impacts are generally less than those associated with fossil-fuel plants. Also associated with geothermal systems are saline waters which must be disposed of. The manner of disposal depends on salinity and water quality. These saline waters must be isolated from contact with ground water regimes.

Land quality problems stem from disturbance due to construction of related facilities, and possible ground subsidence which in turn can cause structural failures and loss of ground water storage capacity.

G. Alternative OCS Exploratory Programs

1. Description

a. Special Limited Leasing in Frontier Areas with Requirements for Prompt Unitized Exploration.

Tracts of flexible size and shape that correspond to geologic structures could be offered in frontier regions. Such leasing would encourage the full development of geologic structures as opposed to limiting development to tracts of 3x3 mi. blocks. Advantages would include the following: no other changes in regulations required, procedures are well established, large areas tend to reduce duplication of exploration effort, large size of tracts will encourage most profitable prospects to be drilled first, large tracts will promote efficient single-company ownership and operation of fields. Disadvantages include the following: most profitable fields are not always largest fields, dilutes total exploration effort by follow-up development drilling, bonus bids may be even larger and more counter-productive in terms of capital demand, and such a change would require an alteration in the law.

b. Leases for Exploration only - Develop Lease upon Discovery (If Leasing Scheduled for Area)

Exploratory oil and gas leases on the OCS except in the Gulf of Mexico and the Southern Cailfornia Continental Borderland have been suggested. The leases would be issued to the highest responsible qualified bidder by competitive bidding. The lease would be for a term of one year and would extend over a set number of acres. An exploratory oil and gas lease would not authorize the production of oil and gas from the leased area except for testing the scope and quantity of any oil and gas discovered. If oil and gas are discovered on the lease during the life of the lease, the company holding the lease shall, without competition or the payment of a bonus, be entitled to a preference right lease covering the discovery. The preference right lease would require a payment of royalty as well as a payment of a share of net profits which would be established by the Secretary of the Interior at the time of issuing the exploratory lease.

c. Federal Exploratory Drilling Program

The Federal Government could conduct its own drilling program on the frontier areas of the Outer Continental Shelf. Such an effort would have to be directed towards the most favorable geological structures since the Government does not presently have the capacity to study all the smaller structures. Even a limited effort by the Government, most likely the U.S. Geological Survey, would put a strain on personnel, procedures for contracting and hiring, and general organizational structure. It would be necessary to immediately contract offshore rigs or else they will be unavailable, which might already be the case. A hostile reaction might be encountered from industry which could result in legal delays. Then of course, industry would also do its normal exploration and research resulting in a duplication of effort. About the only advantage that a Federal Exploratory Drilling Program would be the added knowledge the Government would receive, and perhaps could better evaluate the hydrocarbon resources to be leased.

d. Off Structure Stratigraphic Drilling

1. Federally Conducted

The Federal Government could conduct an off structure stratigraphic drilling program for the purpose of obtaining stratigraphic data. The intent would not be to discover hydrocarbons, but to learn more about the regional geology of the Outer Continental Shelf.

The basic idea of an off structive drilling program is good, but a Federally conducted program would not be practical under existing manpower and budget constraints.

2. Privately Conducted

There is an off structure stratigraphic drilling program presently being conducted privately with Government cooperation off the coast of Texas. This is the only area where such a program is taking place. Such a program can not be instituted on the Atlantic OCS because of existing litigation between the Federal Government and the coastal States.

H. Alternative Lease Bidding Systems

1. Description

a. Royalty Bidding with Fixed Bonus

Under royalty bidding leases would be awarded to the firm that pledged to the Government the highest percentage of future production for an individual tract. Therefore, the bulk of Federal revenues would accrue from royalty payments made if and when production occurred. For the leaseholder this means that Government payments -- aside from a nominal fixed cash bonus -- depend on production. If the leased property is not productive, payments to the Government are not made. Royalty bidding thus means that the risk of an OCS enterprise is shared by both the Government and the leaseholder.

This major advantage of the royalty payment scheme has another side however. Royalty payments, taken off the top, effectively limit leaseholders to receipt of only a fraction of the market price for oil and gas. Depending on the size of the winning royalty bid, the great majority of production could belong to the Government. Production may thus be foregone even when market prices are at a desirable level. Oil and gas wells could be shut down prematurely leaving substantial reserves in the ground To protect against this hazard, royalty reduction stipulations have been established that enable royalty obligations to be diminished over time. These regulations involve conditions that the leaseholder must fulfill prior to the granting a royalty reduction. The stipulations for this rate reduction also limit the lessee's rate of return. It is believed that these provisions will help prevent early abandonment of OCS leases. (These regulations appeared in the Federal Register of July 30, 1974).

Unlike the cash bonus plan, royalty bidding may sometimes foster lease abandonment in those instances where exploration reveals that the original estimates of production revenue were too high. Under cash bonuses, investment in production is only a fraction of the overall investment on which the normal rate of return is originally calculated. If production revenue estimates are revised downward there is still a good chance that return on production investment alone will be in excess of that obtainable by putting the money elsewhere.

This is sometimes not the case with competitive royalty bids. A royalty bid is calculated so that the firm will retain just enough out of expected production revenues to yield a normal rate of return on production investment. If exploratory drilling causes a downward revision in estimated production revenues, a normal rate of return on production investment may no longer be obtainable. Since production investment is the major component of total investment under royalty bidding, and since the decision to invest in production is made after exploratory drilling, a downward re-estimate of production revenues under royalty bidding may sometimes encourage firms to abandon leases

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for more attractive production options. The problem is not really this clear cut because firms will also incorporate risk into their royalty bids. However, lease abandonment is more likely under the royalty rather than the cash bonus methods.

It should also be noted that the most efficient firm may not get the lease under royalty bidding. Any firm can bid a high royalty. If an irresponsible bidder is awarded the lease there may be significant adverse environmental consequences. In the event of a spill or blowout, the firm may lack the resources necessary to prevent widespread damage. However, in the event of such an emergency, the Government could intervene and cleanup under the Regional or National Oil and Hazardous Substances Pollution Contingency Plan.

b. Net Profit Sharing

Two different lease bidding systems fall under the net profit sharing genre. Under a net profit bidding plan, a minimum bonus would be set to discourage irresponsible bidders and firms would compete on the basis of their pledge of a percentage of future net profits to the Government.

As with royalty bidding, payments to the Federal Government would be contingent upon production -- thus shifting some of the risk of OCS development to the Government. Unlike royalty bidding, the production based payment should not by itself induce lease abandonment or premature well shutdown, because the net profit payments will flow from income above and beyond that needed for a normal rate of return. However, there is no guarantee that the most efficient firm will win the lease. Inefficient firms, bidding a high percentage of very small expected net profits, could conceivably get all the leases under this system. The Solicitor's Office of the USDI has indicated that a bidding system of this kind is possible under the current law if:

- regulations are changed to define royalties as a percentage of something equivalent to net profits;
- firms bid on the basis of the royalty rate (percentage of net profits) they are willing to pay.

Profit sharing, the other lease bidding system in this category, would employ cash bonus bidding -- but a fixed percentage of net profits would replace royalty payments. If profit sharing is to be an improvement over the present system, then it should provide for a reduction in the level of the "front-end" bonus bid while simultaneously preventing inefficient firms from winning leases. This will occur if the net profit payment exceeds the expected royalty payment in force under current ground rules. Since the lease will be awarded on the basis of competitive bonus bidding, the winning firm will be the one that places the highest net value on the lease at the present time. The efficiency of this firm is assured because this firm's expected net value is the highest after costs have been covered and profits shared.

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The advantages of a net profit sharing system are realized only when:

1. "Net profits" are defined as net income on property after taxes.
2. Net profit payments are a share of "net profits" involving a return on investment in excess of a normal rate of return.

These two conditions are not valid under current tax law. Net profit payments must be calculated prior to tax liability beacuse they are considered as deductions from gross income on property. The second condition above requires a definition of exploration and capital costs distinct from that now used for tax purposes.

C. Deferred Bonuses

Under a deferred bonus system, firms still compete on the basis of bonus payments but with the understanding that the bonus payment will occur over time rather than in one lump sum. For this system to conform to the present law, the bonus payment must be defined as the rental payments during the first five years of the lease. Under this system, the equivalent to current bonus payments would be six times what the firm bids -- the bonus payment plus the first five rental payments.

There is really no shifting of the risk in OCS development from the leaseholder to the Government under deferred bonuses. Payments to the

Government are made during the lease's non-productive years and regardless of whether or not production ever takes place.

The advantage of deferred bonuses is that they provide relief to the smaller firm. Such a firm, which might be an efficient and responsible producer, may be at a competitive disadvantage under the current system because of the difficulty it will encounter in trying to assemble the huge sums --- from either retained earnings or the money market -- now needed to make cash bonus payments during the first year of the lease. The relief is in the form of spreading out the cash flow involved in paying for the right to explore and develop OCS leases.

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I. Alternative Management and Supervisory Systems

1. Description

a. Place All Management and Supervisory Functions Under One Agency

It has been suggested that many of the management and supervisory problems of OCS leasing (and energy policy in general) would be reduced by assembling all jurisdictional offices in one agency. The most frequently mentioned name for such an agency is the Department of Energy and Natural Resources (President Nixon proposed this Department in his Energy Message of 1973). The intended result of such a consolidation is a reduction in the necessity of interagency communication and division of responsibilities among agencies. The multi-agency responsibilities were outlined in Section I of this statement. There is considerable difficulty and competing interest in multi-agency control of programs. However, the present system, with BLM having the lead in management aspects and USGS having the lead in supervisory aspects, has developed over time to a workable relationship between those two groups and the other groups having responsibilities.

On the other hand, it has also been suggested that the present separated system is better than any proposed consolidation, simply because the divided responsibilities insure checks and balances on the program. See next section.

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b. Divide Management and Supervisory Functions Between or Among Agencies

One major criticism of the present leasing system has been that there is an inherent conflict within the Department of the Interior because the Department, under the OCS Lands Act and NEPA, must both promulgate programs and then objectively evaluate them. In the leasing program, this conflict centers on the fact that BLM is the lead agency in proposing sales (site and size) and in writing environmental impact statements concerning those sales. It has been suggested from several sources that these functions should be separated, even to the extent of having one function in one agency and the other in another agency (e.g., leasing in Interior, environmental assessment in Commerce under NOAA). The Environmental Protection Agency has also been mentioned as the possible environmental assessment agency. Presumably this separation would reduce the possibility of parochial interest in programs and insure that multiple uses of the OCS would be more equally considered.

The possibility of conflict was considered in the early stages of the impact statement program soon after the enactment of NEPA in 1969. This possibility is mitigated by the wide distribution of impact statements for Federal, State and public review and comment.

c. Consolidate Present Leasing Functions of BLM and Presen Supervisory Functions of USGS Under One Bureau in Department of the Interior

This alternative is essentially the same as in a. above closer coordination might be possible with such an arrangement, especially in the pre-sale stages and in evaluation of tracts for lease The geophysical information gathered by industry is purchased by USGS and is held on a proprietary basis. Personnel in BLM generally do not see this material and do not have the expertise to evluate it. The USGS provides interpretation of such data to BLM for pre-sale evaluatio and tract selection. This proposal has merit from the standpoint of BL being more aware of operating practices and supervisory procedures, but the separation of functions was instituted to permit independent supervision of the program.

d. Same System as Proposed Action But With Increased Funding and/or Personnel

It is felt in some quarters that increased funding and/or personnel can solve nearly all problems. The OCS leasing program has been expanding rapidly in the last few years and this has necessitated larger budgets and staffs both for BLM and USGS. Significant funding has been granted BLM for the conduct of the environmental baseline and monitoring studies outlined in Section I. of this statement. It has also been mentioned that the present staffing and funding for BLM appear adequate for management of this proposed action, and that USGS' budget requests for increased staff should be adequate to supervise the program in the short term. Full scale development of 10 million acres will take several years, however, a fact that allows necessary adjustments of fiscal and staffing needs to be made in the future as conditions then require.

e. Promulgation of OCS Orders for Frontier Areas

As each frontier area is opened, OCS Orders will be written, at least in draft form, for inclusion in the EIS for the first proposed sale in each area. These OCS Orders implement the requirements of the regulations contained in Title 30 CFR Chapter II Part 250 "Oil and Gas and Sulphur Operations in the Outer Continental Shelf.

The OCS Orders are revised from time to time to reflect advances in technology and overall knowledge of weather, sea and geologic conditions in the area covered by the orders.

J. Alternative Technology Options

1. Description

Advances in technology usually appear in an incremental basis, and a common criticism of present regulations, orders and standards is that they are promulgated in response to the ability of industry to attain the standards or comply with the orders.

A requirement to use the best available demonstrated environmental control technology would strengthen the commitment toward one of the goals of the leasing program -- protection of the environment. But, as Dyer, et al. (1971) pointed out in the NASA study of OCS technologies, there was a lack of a systematic approach to equipment design and inadequate or non-existent quality control procedures. Kash, et al. (1973) pointed out that several problems still existed in 1973, including: 1) continued incremental and component-by-component development of technologies; 2) lack of a formal system to identify and correct deficient technologies; and 3) weak inspection and quality control systems. Numerous recommendations were made by Kash, et al., but the most salient with respect to any requirement to use the best available demonstrated environmental control technology is a greater emphasis on the systems design approach to establish performance standards and specifications for individual components. This concept appears to be a particularly valid one in light of the proposed action. This requirement has not been specifically stated in a regulation or operating order, but the concept pervades the management and supervisory authorities which develop and amend regulations, orders, notices, and stipulations, and the development of new technologies. The increase in drilling and production activity will necessitate a major effort in platform and pipeline construction. New geographic areas will have to be opened to leasing if this proposal is implemented. This combination of factors indicates that this may be the time when more stringent requirements and better designed technologies should be demanded.

The cost to convert existing OCS operations to "best available demonstrated environmental control technology" would be prohibitive unless the conversion process were extended over an extremely long time period. Even to require "best available demonstrated environmental control technology" in frontier areas runs the risk of reducing or even curtailing operations in some other wise favorable locations by changing the economics from profitable to unprofitable.

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ATTACHMENT A

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TITLE 30, CODE OF FEDERAL REGULATIONS

PART 250 - OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

PART 290 - APPEALS PROCEDURES

ART 250 — OIL AND GAS AND ULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

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MINERAL LEASES AFFECTED BY SECTION 6 OF OUTER CONTINENTAL SHELF LANDS ACT

250.100 Effect of regulations on provisions of lease.

AUTHORITY: The provisions of this Part 250 issued under secs. 5, 6, 67 Stat. 464, 465; 43 U.S.C. 1334, 1335.

SOURCE: The provisions of this Part 250 appear at 19 F.R. 2656, May 8, 1954, unless otherwise noted.

CROSS REFERENCE: For further regulations pertaining to the issuance and recognition of mineral leases covering submerged lands in the Outer Continental Shelf, see 43 CFR Part 3300.

GENERAL PROVISIONS

§250.1 Purpose and authority.

The Outer Continental Shelf Lands Act enacted on August 7, 1953 (67 Stat. 462), referred to in this part as "the act," authorizes the Secretary of the Interior at any time to prescribe and amend such rules and regulations, to be applicable to all operations conducted under a lease issued or maintained under

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the provisions of the act, as he determines to be necessary and proper to provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf, and the protection of correlative rights therein. Subject to the supervisory authority of the Secretary of the Interior, the regulations in this part shall be administered by the Director of the Geological Survey through the Chief, Conservation Division. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

250.2 Definitions.

The following terms as used in the regulations in this part shall have the meanings here given:

(a) *Secretary.* The Secretary of the Interior.

(b) *Director.* The Director of the Geological Survey, Washington, D.C., having direction of the enforcement of the regulations in this part. [As amended at 38 F.R. [illegible], April 23, 1973.]

(c) *Supervisor.* The Area Oil and Gas Supervisor, Conservation Division of the Geological Survey; a representative of the Secretary, subject to the direction and supervisory authority of the Director, through the Chief, Conservation Division, Geological Survey, and the appropriate Conservation Manager, Conservation Division, Geological Survey, authorized and empowered to regulate operations and to perform other duties prescribed in the regulations in this part, or any subordinate of such representative acting under his direction. [As amended at 38 F.R. 10003, April 23, 1973.]

(d) *Outer Continental Shelf.* All submerged lands (1) which lie seaward and outside of the area of lands beneath navigable waters as defined in the Submerged Lands Act (67 Stat. 29) and (2) of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

(e) *Lease.* The contract or agreement under which the leasehold rights are held by the lessee, or the land covered by the contract or agreement, whichever is required by the context.

(f) *Lessee.* The party authorized by a lease, or an approved assignment thereof, to develop and produce the leased deposits in accordance with the regulations in this part, including all parties holding such authority by or through him.

(g) *Operator.* The individual, partnership, firm, or corporation having control or management of operations on the leased land or a portion thereof. The operator may be a lessee, designated agent of the lessee, or holder of rights under an approved operating agreement.

(h) *Waste of oil and gas.* Waste means and includes (1) physical waste as that term is generally understood in the oil and gas industry; (2) the inefficient, excessive, or improper use of, or the unnecessary dissipation of reservoir energy; (3) the locating, spacing, drilling, equipping, operating, or producing of any oil or gas well or wells in a manner which causes or tends to cause reduction in the quantity of oil or gas ultimately recoverable from a pool under prudent and proper operations or which causes or tends to cause unnecessary or excessive surface loss or destruction of oil or gas; (4) the inefficient storage of oil; and (5) the production of oil or gas in excess of transportation or marketing facilities or in excess of reasonable market demand.

(i) *Directional drilling.* The deviation of a bore hole from the vertical or from its normal course in an intended predetermined direction or course with respect to the points of the compass. Directional drilling shall not include deviations made for the purpose of straightening a hole that has become crooked in a normal course of drilling or deviating a hole at random without regard to compass direction in an attempt to sidetrack a portion of the hole on account of mechanical difficult in drilling.

(j) *OCS Order.* A formal numbered order issued by the supervisor and available in his office, with the prior approval of the Chief, Conservation Division, Geological Survey, that implements the regulation in this part and applies to operations in a region or a major portion thereof.

(k) *Pollution Contingency Plan.* The National Multi-Agency Oil and Hazardous Materials Pollution Contingency Plan cosigned by the Department of the Interior, Department of Transportation, Department of Defense, Department of Health, Education, and Welfare, and the Office of Emergency Preparedness and administered by the Secretary of the Interior, or any successor plan thereto. [As amended at 34 F.R. 135[illegible], Aug. 22, 1969.]

§250.10 Jurisdiction.

Subject to the supervisory authority of the Secretary and the Director, drilling and production operations, handling, and measurement of production, determination and collection of rental and royalty, and in general, all operations conducted on a lease by or on behalf of a lessee are subject to the regulations in this part, and are under the jurisdiction of the Supervisor for any area as delineated by the Director. In the exercise of this jurisdiction, the Supervisor shall be subject to the direction and supervisory authority of the Chief, Conservation Division, and the appropriate Conservation Manager, Conservation Division, Geological Survey, each of whom may exercise the jurisdiction of the Supervisor. [As amended at 30 F.R. 10003, Apr. 23, 1973.]

2!.11 General functions.

'ie supervisor is authorized and directed to act pc the requests, applications, and notices submitted nc the regulations in this part and to require on liance with applicable laws, the lease terms, pp:able regulations, and OCS Orders to the end that ll perations shall be conducted in a manner which ill protect the natural resources of the Outer or nental Shelf and result in the maximum economic cc ery of the mineral resources in a manner on atible with sound conservation practices. Subject e approval of the Chief, Conservation Division, eo gical Survey, the supervisor may issue OCS rcrs implementing the requirements of the gutions of this part when such implementations pp to an entire region or a major portion thereof. he supervisor may issue written or oral orders to ov n lease operations. Oral orders shall be confirmed iting by the supervisor as promptly as possible. he supervisor may issue other orders, and rules to ov n the development and method of production of pol, field, or area. Prior to the issuance of OCS rd s and other orders and rules, the supervisor may on lt with, and receive comments from, lessees, p ators, and other interested parties. Before er tting operations on the leased land, the supervisor a require evidence that a lease is in good standing, ha he lessee is authorized to conduct operations, and ha n acceptable bond has been filed. [As amended F.R. 13544, Aug. 22, 1969.]

25 12 Regulation of operations.

(*Duties of supervisor.* The supervisor in cc lance with the regulations in this part shall sp t and regulate all operations and is authorized to su OCS Orders and other orders and rules necessary r im to effectively supervise operations and to ev t damage to, or waste of, any natural resource, ury to life or property. The supervisor shall ce e, and shall, when in his judgment it is necessary, ons t with or solicit advice from lessees, field ffic ls of interested Departments and agencies, cl ing the Fish and Wildlife Service, Federal Water oll ion Control Administration, Bureau of Land an ement, Coast Guard, Department of Defense, or of Engineers, and representatives of State and ca governments.

(*Departures from orders.* (1) The supervisor may res ibe or approve in writing, or orally with written on mation, minor departures from the requirements f CS Orders and other orders and rules issued ur nt to (a) of this section, when such departures re necessary for the proper control of a well, on vation of natural resources, protection of aquatic fe, rotection of human health and safety, property, r t environment.

(All requests or recommendations for major ep ures from the requirements of OCS Orders, whether on an individual well or field basis shall be approved by the Chief, Conservation Division.

(c) *Emergency suspensions.* The supervisor is authorized, either in writing or orally with written confirmation, to suspend any operation, including production, which in his judgment threatens immediate, serious, or irreparable harm or damage to life, including aquatic life, to property, to the leased deposits, to other valuable mineral deposits or to the environment. Such emergency suspension shall continue until in his judgment the threat or danger has terminated.

(d) *Other suspensions.* (1) In addition to the provisions of section 12 (c) and (d) of the act providing for suspension of operations and production, in the interest of conservation the supervisor may direct or, at the request of a lessee, may approve the suspension of operations or production, or both, including the approval of suspension of production for (i) leases on which a well has been drilled and determined by the supervisor to be capable of being produced in paying quantities and thereafter temporarily abandoned or permanently plugged and abandoned to facilitate proper development of the lease, and (ii) leases on which a well has been drilled and determined by the supervisor to be capable of being produced in paying quantities, but which cannot be produced because of the lack of transportation facilities. Suspensions of operations or production, or both, may be approved for an initial period, not exceeding 2 years, and for succeeding periods, not exceeding 1 year each.

(2) As to any leases maintained under section 6 of the act covering minerals in addition to oil and gas, the supervisor may suspend operations separately as to oil and gas or as to any other mineral designated in the suspension, order, or grant.

(3) The supervisor is authorized by written notice to the lessee to suspend any operation, including production, for failure to comply with applicable law, the lease terms, the regulations in this part, OCS Orders, or any other written order or rule including orders for filing of reports and well records or logs within the time specified.

(e) *Reduction of rental and royalty.* In order to increase the ultimate recovery of minerals and in the interest of conservation, the Director of the Geological Survey, whenever he determines it necessary to promote development or finds that a lease cannot be successfully operated under the terms provided therein, may reduce the rental, minimum royalty, or royalty on the entire leasehold, or on any deposit, tract, or portion thereof segregated for royalty purposes. An application for any of the above relief shall be filed in triplicate with the Director of the Geological Survey. It must contain the serial number of the lease; the name of the record title holder; a description of the area included in the lease; the number, location, and status of each well that has been drilled; a tabulated statement for each month, covering a period of not less than 6 months prior to the date of filing the application, of the aggregate amount of minerals subject to royalty computed in accordance with the lease and applicable regulations. Every application must also contain a detailed statement of expenses and costs of operating the entire lease and of the income from the sale of any leased products, and all facts tending to show whether the wells or workings can be successfully operated upon the rental or royalty fixed in the lease. Where the application is for a reduction of royalty, full information shall be furnished as to whether royalties or payments out of production are paid to others than the United States, the amounts so paid, and efforts made to reduce them. The applicant must also file agreements of the holders of the lease and of royalty holders to a permanent reduction of all other royalties from the leasehold to an aggregate not in excess of one half the Government royalties. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

250.13 Temporary approvals.

Whenever the regulations in this part require a lessee to obtain approval of the supervisor, the lessee may make an oral or telegraphic request for such approval, and the supervisor may give such oral or telegraphic approval as may be warranted: *Provided,* That the transaction shall forthwith be confirmed in the manner otherwise required by the regulations in this part.

250.14 Samples, tests, and surveys.

(a) When deemed necessary or advisable, the supervisor is authorized to require that adequate tests or surveys be made in an acceptable manner without cost to the lessor to determine the reservoir energy; the presence, quantity, and quality of oil, gas, sulphur, other mineral deposits, or water; the amount and direction of deviation of any well from the vertical; or the formation, casing, tubing, or other pressures.

(b) The supervisor may, at the time of approval of any notice to drill or redrill any well, stipulate reasonable requirements for the taking of formation samples or cores to determine the identity and character of any formation.

§ 250.15 Drilling and abandonment of wells.

The supervisor shall demand drilling in accordance with the terms of the lease and of the regulations in this part; and shall require plugging and abandonment, in accordance with such plan as may be approved or prescribed by him, of any well no longer used or useful, and upon failure to secure compliance with such requirement, perform the work at the expense of the lessee, expending available public funds, and submit such report as may be needed to furnish a basis for appropriate action to obtain reimbursement.

§250.16 Well potentials and permissible flow.

The supervisor is authorized to specify the time and method for determining the potential capacity any well and to fix, after appropriate notice, the permissible production of any such well that may be produced when such action is necessary to prevent waste or to conform with such proration rules, schedules, or procedures as may be established the Secretary.

§250.17 Well locations and spacing.

The supervisor is authorized to approve well locations and well spacing programs necessar for proper development giving consideration to such factors as the location of drilling platforms the geological and reservoir characteristics of the field the number of wells that can be economically drille the protection of correlative rights, and minimizing unreasonable interference with other uses of the Outer Continental Shelf area. [As amended and renamed "Well Locations and Spacing" from "Well Spacing and Well Casing" at 34 F.R. 13544, Aug. 22, 1969.]

§250.18 Rights of use and easement.

(a) In addition to the rights and privileges granted to a lessee under any lease issued or maintained under the act, the supervisor may grant such lessee, subject to such reasonable conditions as said supervisor may prescribe, the right of use or an easement to construct and maintain platforms, fixed structures, and artificial islands, and to use the same for carrying on operations including drilling, directional drilling, producing, treating, handling, and storing production, and housing personnel engaged in operations, not only in connection with the lease on which the platform, structure, or island, is situated, but for the conduct of operations on any other lease, State or Federal.

(b) The supervisor may grant to a holder of a Federal or State lease the right of use or an easement to construct and maintain platforms, fixed structures, and artificial islands on areas of the Outer Continental Shelf, near or adjacent to the leased area, and to use the same for drilling directional well or wells to be bottomed under the leased area, and for producing and reworking such well or wells, and for handling, treating, and storing the production therefrom. Such rights of use or easement if on an area subject to any mineral lease issued or maintained under the act shall be granted only after the lessee under such lease has been notified and afforded an opportunity to present objections thereto, and any such right shall be exercised only in such manner so as not to interfere unreasonably with operations of the lessee under such lease.

(c) In addition to the rights and privileges granted to a Federal lessee under any lease issued or maintained under the act, the supervisor upon p application may grant to a holder of a Federal lease or State lease issued by a State which extends the same rights to holders of Federal leases, subject to such reasonable conditions as the supervisor may prescribe, the right of use or an easement to construct and maintain pipelines on areas of the Outer Continental Shelf which are constructed, owned, and maintained by the lessee and used for purposes such as (1) moving production to a central point for gathering, treating, storing, or measuring; (2) delivery of production to a point of sale; (3) delivery of production to a pipeline operated by a transportation company; or (4) moving fluids in connection with lease operations, such as for injection purposes. The supervisor is authorized to approve any reasonable offshore or onshore location as the central or delivery point. Rights of use or easement across areas covered by a mineral lease issued or maintained under the act shall be granted only after the lessee under such lease has been notified by the applicant and afforded a reasonable opportunity to express its views with respect thereto, and any such rights shall be exercised only in a manner so as not to interfere unreasonably with operations of the lessee under such lease. The foregoing right of use and easement shall not apply to pipelines used for transporting oil, gas, or other production after custody has been transferred to a purchaser or carrier as provided for in section 5(c) of the Outer Continental Shelf Lands Act and regulations in 43 CFR 2234 5-3. [Now 43 CFR 2883.]

) Once a right of use or easement has been exercised by the erection of platforms, fixed structures, artificial islands, or pipelines, the right shall continue only so long as they are maintained and are used for the purpose specified therein, as determined by the supervisor, even beyond the termination of any lease on which they may be situated, and the rights of subsequent lessees shall be subject to such rights of use and easement by prior lessees. Upon termination by the supervisor of the right of use and easement, the lessee shall remove or otherwise dispose of all platforms, fixed structures, artificial islands, pipelines, and other facilities and restore the premises to the satisfaction of the supervisor; provided, however, that pipelines may be abandoned in place for so long as they do not constitute a navigational or other hazard as determined by the supervisor. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.19 Platforms and pipelines.

(a) The supervisor is authorized to approve the design, other features, and plan of installation of all platforms, fixed structures, and artificial islands as a condition of the granting of a right of use or easement under paragraphs (a) or (b) of §250.18 or authorized under any lease issued or maintained under the act.

(b) The supervisor is authorized to approve the other features, and plan of installation of all pipelines for which a right of use or easement has been granted under paragraph (c) of §250.18 or authorized under any lease issued or maintained under the act, including those portions of such lines which extend onto or traverse areas other than the Outer Continental Shelf. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.20 Rentals, royalties, and other payments.

The supervisor shall determine pursuant to the lease and regulations the rental and the amount or value of production accruing to the lessor as royalty, the loss through waste or failure to drill and produce protection wells on the lease, and the compensation due to the lessor as reimbursement for such loss. [250.20 is revoked and 250.19 is redesignated as 250.20 at 34 F.R. 13544, Aug. 22, 1969.]

REQUIREMENTS FOR LESSEES

§250.30 Lease terms, regulations, waste, damage, and safety.

The lessee shall comply with the terms of applicable laws and regulations, the lease terms, OCS Orders and other written orders and rules of the supervisor, and with oral orders of the supervisor. All such oral orders shall be effective when issued, and are to be confirmed in writing as provided in §250.11. The lessee shall take all necessary precautions to prevent damage to or waste of any natural resource or injury to life, or property, or the aquatic life of the seas. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.31 Designation of operator.

In all cases where operations are not conducted by the record owner but are to be conducted under authority of an unapproved operating agreement, assignment, or other arrangement, a "designation of operator" shall be submitted to the supervisor, in a manner and form approved by him, prior to commencement of operations. Such designation will be accepted as authority of operator or his local representative to fulfill the obligations of the lessee and to sign any papers or reports required under the regulations in this part. All changes of address and any termination of the authority of the operator shall be immediately reported, in writing, to the supervisor or his representative. In case of such termination or controversy between the lessee and the designated operator, the operator, if in possession of the lease, will be required to protect the interests of the lessor.

§250.32 Local agent.

When required by the supervisor, the lessee shall designate a representative empowered to receive notices and comply with orders of the supervisor issued pursuant to the regulations in this part.

§250.33 Drilling and producing obligations.

(a) The lessee shall diligently drill and produce such wells as are necessary to protect the lessor from loss by reason of production on other properties, or in lieu thereof, with the consent of the supervisor, shall pay a sum determined by the supervisor as adequate to compensate the lessor for failure to drill and produce any such well. In the event that the lease is not being maintained in force by other production of oil or gas in paying quantities or by other approved drilling or reworking operations, such payments shall be considered as the equivalent of production in paying quantities for all purposes of the lease.

(b) The lessee shall promptly drill and produce such other wells as the supervisor may reasonably require in order that the lease may be properly and timely developed and produced in accordance with good operating practices.

§250.34 Drilling and development programs.

(a) *Exploratory drilling plan.* Prior to commencing each exploratory drilling program on a lease, including the construction of platforms, the lessee shall submit a plan to the supervisor for approval. Each plan for the leased area shall include (1) a description of drilling vessels, platforms, or other structures showing the location, the design, and the major features thereof, including features pertaining to pollution prevention and control; (2) the general location of each well including surface and projected bottom hole location of directionally drilled wells; (3) structural interpretation based on available geological and geophysical data; and (4) such other pertinent data as the supervisor may prescribe.

(b) *Development plan.* Prior to commencing each development program on a lease, the lessee shall submit a plan to the supervisor for approval. The plan shall include all information specified in paragraph (a) of this section in detail.

(c) *Drilling applications.* Prior to commencing drilling operations either under an exploratory or development plan, the lessee shall submit an Application for Permit to Drill (Form 9-331C) to the supervisor for approval. The application shall include the integrated blowout prevention, mud, casing, and cementing program for the well, and shall meet the requirements specified in §250.41(a), and contain the information specified in §250.91(a), and shall conform with the approved exploratory or development plan.

(d) *Modifications.* The lessee shall submit: (1) All requests for modifications of an approved exploratory or development plan in writing to the supervisor for approval, and (2) all notices of changes to plans set forth in the approved Application for Permit to Drill on Sundry Notices and Reports on Wells (F m 9-331), except that these requirements shall not re ve the lessee from taking appropriate action to preve or abate damage, waste, or pollution of any nat al resource or injury to life or property. [As amende at 34 F.R. 13544, Aug. 22, 1969.]

§250.35 Extension of leases by drilling or ll reworking.

(a) The Secretary shall be deemed to e approved, within the meaning of section 8(b)(2) of e Outer Continental Shelf Lands Act, drilling or ll reworking operations, conducted on the leased are n the following instances:

(1) If, after discovery of oil or gas in pay g quantities has been made on the leasehold and wit n 90 days prior to expiration of the five-year term r any extension thereof, or thereafter, the product n thereof shall cease at any time, or from time to ti , from any cause and production is restored or drill g or well reworking operations are commenced within days thereafter, and such drilling or well rework g operations (whether on the same or different wells) e prosecuted diligently until production is restored paying quantities.

(2) If, within 90 days prior to expiration of t five-year term or any extension thereof, or thereaft at any time, or from time to time, lessee is engaged drilling or well reworking operations on the leaseho and there is no well on the leasehold capable producing in paying quantities and the lessee diligen prosecutes such operations (whether on the same different wells) with no cessation of more than days.

(b) The Secretary may approve such oth operations for drilling or reworking upon applicati of lessee.

(c) Nothing in this section obviates the necessity obtaining the supervisor's approval of a plan or notic of intention to drill or of complying with the othe provisions of this part. [24 F.R. 9527. Nov. 28, 195 as redesignated from 250.34a at 34 F.R. 13544, Aug 22, 1969.]

§250.36 Subsequent well operations.

Prior to commencing operations not previousl approved, such as deepening, plugging-back, repairin (other than work incidental to ordinary wel operations), acidizing or stimulating production b other methods, perforating, sidetracking, squeezin with mud or cement, abandoning, and any simila operation which will alter the condition of a well, th lessee shall submit an application or notice as specifie in §250.91 and 250.92 to the supervisor for approval is requirement shall not relieve the lessee from king appropriate action to prevent or abate damage waste of any natural resource, or injury to life or operty. [As amended and redesignated from 250.35 34 F.R. 13544, Aug. 22, 1969.]

250.37 Well designations.

The lessee shall mark promptly each drilling atform or structure in a conspicuous place, showing s name or the name of the operator, the serial mber of the lease, the identification of the wells, d shall take all necessary means and precautions to serve these markings. [As redesignated from 250.36 34 F.R. 13544, Aug. 22, 1969.]

50.38 Well records.

(a) The lessee shall keep for each well at his field headquarters or at other locations conveniently available to the supervisor, accurate and complete records of all well operations including production, drilling, logging, directional well surveys, casing, perforating, safety devices, redrilling, deepening, repairing, cementing, alterations to casing, plugging, and abandoning. The records shall contain a description of any unusual malfunction, condition or problem; all the formations penetrated; the content and character of oil, gas, and other mineral deposits, and water in each formation; the kind, weight, size, grade, and setting depth of casing; and any other pertinent information.

(b) Upon request of the supervisor, the lessee shall immediately transmit copies of records of any of the well operations specified in paragraph (a) of this section; however, in any event the lessee shall, within 30 days after completion of any well, transmit to the supervisor copies of the records of all operations (except logging) in duplicate on or attached to Form 9-30, except that when operations are suspended the lessee shall transmit copies of the records of all operations conducted thereon to the supervisor within 30 days after the suspension; and within 30 days after the suspension or completion of any further operations, including those described in §250.92, the lessee shall transmit to the supervisor copies of the records of such operations in duplicate on or attached to Form 9-330 or Form 9-331, as appropriate.

(c) Upon request by the supervisor, the lessee shall submit paleontological reports identifying microscopic fossils by depth (not the resulting interpretations based upon such identifications) unless washed well samples normally maintained by the lessee for paleontological determinations are made available to the supervisor for inspection.

(d) Upon request of the supervisor, the lessee shall immediately transmit copies (field or final prints of individual runs) of logs or charts of electrical, radioactive, sonic, and other well logging operations and directional well surveys. Composite logs of multiple runs and directional well surveys shall be transmitted to the supervisor in duplicate as soon as available, but not later than 30 days after completion of such operations for each well.

(e) Upon request of and in the manner and form prescribed by the supervisor, the lessee shall furnish copies of the daily drilling report and a plat showing the location, designation, and status of all wells on the leased lands.

(f) Upon request of the supervisor, the lessee shall furnish legible, exact copies of service company reports on cementing, perforating, acidizing, analyses of cores, or other similar services.

(g) The lessee shall submit any other reports and records of operations when required and in the manner and form prescribed by the supervisor. [As amended and redesignated from 250.37 at 34 F.R. 13544, Aug. 22, 1969.]

§250.39 Samples, tests, and surveys.

(a) The lessee, when required by the supervisor, shall make adequate tests or surveys in an acceptable manner, without cost to the lessor, to determine the reservoir energy; the presence, quantity, and quality of oil, gas, sulphur, other mineral deposits, or water; the amount and direction of deviation of any well from the vertical; or the formation, casing, tubing, or other pressures.

(b) The lessee shall take such formation samples or cores to determine the identity and character of any formation in accordance with reasonable requirements of the supervisor prescribed at the time of approval of the notice to drill or redrill any well. [As redesignated from 250:38 at 34 F.R. 13544, Aug. 22, 1969.]

§250.40 Directional survey.

(a) An angular deviation and directional survey shall be made of the finished hole of each well directionally drilled.

(b) The supervisor, at the request of an offset lessee made prior to completion of a well, may require a lessee of an adjoining lease to make or furnish a directional survey of any hole, at the risk and expense of the offset lessee making such request. A copy of such directional survey shall be furnished to the supervisor and the offset lessee. If it is determined that such well is closer to the line of the offset lease than one-half (1/2) the required distance from such line fixed by an approved spacing program or by special field rules, the risk and expense of making such directional survey shall be borne by the offending lessee; and, unless and until the hole is promptly straightened to correct the offense, the supervisor may reduce the allowable production from the well to prevent its draining unduly the offset leased area. Neither the imposition of any penalty or of the costs of such survey upon the offending lessee nor the reduction of the allowable production from the well is intended to prejudice any other remedy which the affected parties may have. [As redesignated from 250.39 at 34 F.R. 13544, Aug. 22, 1969.]

§250.41 Control of wells.

(a) *Drilling wells.* The lessee shall take all necessary precautions to keep all wells under control at all times, shall utilize only personnel trained and competent to drill and operate such wells, and shall utilize and maintain materials and high-pressure fittings and equipment necessary to insure the safety of operating conditions and procedures. The design of the integrated casing, cementing, drilling mud, and blowout prevention program shall be based upon sound engineering principles, and must take into account the depths at which various fluid or mineral-bearing formations are expected to be penetrated, and the formation fracture gradients and pressures expected to be encountered, and other pertinent geologic and engineering data and information about the area.

(1) *Well casing and cementing.* The lessee shall case and cement all wells with a sufficient number of strings of casing in a manner necessary to: (i) Prevent release of fluids from any stratum through the well bore (directly or indirectly) into the sea; (ii) prevent communication between separate hydrocarbon-bearing strata (except such strata approved for commingling) and between hydrocarbon and water-bearing strata; (iii) prevent contamination of fresh water strata, gas, or water; (iv) support unconsolidated sediments; and (v) otherwise provide a means of control of the formation pressures and fluids. The lessee shall install casing necessary to withstand collapse, bursting, tensile, and other stresses and the casing shall be cemented in a manner which will anchor and support the casing. Safety factors in casing program design shall be of sufficient magnitude to provide optimum well control while drilling and to assure safe operations for the life of the well. When directed by the supervisor, the lessee shall install structural or drive casing to provide hole stability for the initial drilling operation. A conductor string of casing (the first string run other than any structural or drive casing) must be cemented with a volume of cement sufficient to circulate back to the sea floor; however, if authorized by OCS Order or the supervisor, cement may be washed out or displaced to a specified depth below the sea floor to facilitate casing removal upon well abandonment. All subsequent strings must be securely cemented.

(2) *Drilling mud.* The lessee shall maintain readily accessible for use quantities of mud sufficient to insure well control. The testing procedures, characte ties, and use of drilling mud and the conduct of ated drilling procedures shall be such as are neces to prevent blowouts. Mud testing equipment an mud volume measuring devices shall be maintained all times, and mud tests shall be performed frequent and recorded on the driller's log as prescribed b the supervisor.

(3) *Blowout prevention equipment.* The lesse hall install, use, and test blowout preventers and r ated well-control equipment in a manner necessa to prevent blowouts. Such installation, use and t ting must meet the standards or requirements prescrib by the supervisor; provided, however, in no event sh the lessee conduct drilling below the conductor stri of casing until the installation of at least one ren tely controlled blowout preventer and equipmen for circulating drilling fluid to the drilling structu or vessel. Blowout preventers and related well-c trol equipment shall be pressure tested when installed, fter each string of casing is cemented, and at such her times as prescribed by the supervisor. Bl out preventers shall be activated frequently to te for proper functioning as prescribed by the supervis All blowout-preventer tools shall be recorded or the driller's log.

(b) *Completed wells.* In the conduct of a its operations, the lessee shall take all steps necessa to prevent blowouts, and the lessee shall immediately ake whatever action is required to bring under contr any well over which control has been lost. The lessee all: (1) In wells capable of flowing oil or gas, hen required by the supervisor, install and mainta in operating condition storm chokes or similar subsu ace safety devices; (2) for producing wells not capab of flowing oil or gas, install and maintain surface s ety valves with automatic shutdown controls; an (3) periodically test or inspect such devices or equip ent as prescribed by the supervisor. [As amended 25 F.R. 637, Jan. 26, 1960. As amended and redesig ted from 250.40 at 34 F.R. 13544, Aug. 22, 1969.]

§250.42 Emulsion and dehydration.

(a) The lessee shall complete and maintain al oil wells in such mechanical condition and operate em in such manner as to prevent, so far as possible he formation of emulsion and basic sediment.

(b) The lessee shall put in marketable conditio commercially feasible, all products produced from he leased land and pay royalty thereon without rec s to the lessor for deductions on account of cost of treatment. [Redesignated from 250.41 at 34 R. 13544, Aug. 22, 1969.]

§250.43 Pollution and waste disposal.

(a) The lessee shall not pollute land or wate or damage the aquatic life of the sea or allow extran natter to enter and damage any mineral- or water-earing formation. The lessee shall dispose of all liquid nd nonliquid waste materials as prescribed by the pervisor. All spills or leakage of oil or waste aterials shall be recorded by the lessee and, upon quest of the supervisor, shall be reported to him. All ills or leakage of a substantial size or quantity, as efined by the supervisor, and those of any size or antity which cannot be immediately controlled also all be reported by the lessee without delay to the pervisor and to the Coast Guard and the Regional irector of the Federal Water Pollution Control dministration. All spills or leakage of oil or waste aterials of a size or quantity specified by the signee under the pollution contingency plan shall o be reported by the lessee without delay to such signee.

(b) If the waters of the sea are polluted by the lling or production operations conducted by or on half of the lessee, and such pollution damages or threatens to damage aquatic life, wildlife, or public or private property, the control and total removal of the pollutant, wheresoever found, proximately resulting therefrom shall be at the expense of the lessee. Upon failure of the lessee to control and remove the pollutant the supervisor, in cooperation with other appropriate agencies of the Federal, State and local governments, or in cooperation with the lessee, or both, shall have the right to accomplish the control and removal of the pollutant in accordance with any established contingency plan for combating oil spills or by other means at the cost of the lessee. Such action shall not relieve the lessee of any responsibility as provided herein.

c) The lessee's liability to third parties, other than for cleaning up the pollutant in accordance with paragraph (b) of this section shall be governed by applicable law. [As amended at 34 F.R. 2503, Feb. 21, 1969, and amended and redesignated from 250.42 at 34 F.R. 13544, Aug. 22, 1969.]

§250.44 Well abandonment.

he lessee shall promptly plug and abandon any well on the leased land that is not used or useful, but no productive well shall be abandoned until its lack of capacity for further profitable production of oil, gas, or sulphur has been demonstrated to the satisfaction of the supervisor. Before abandoning a producible well, the lessee shall submit to the supervisor a statement of reasons for abandonment and his detailed plans for carrying on the necessary work. A producible well may be abandoned only after receipt of written approval by the supervisor. No well shall be plugged and abandoned until the manner and method of plugging shall be approved or prescribed by the supervisor. Equipment shall be removed, and premises at the well-site shall be properly conditioned immediately after plugging operations are completed on any well when directed by the supervisor. Drilling equipment shall not be removed from any suspended drilling well without taking adequate measures to protect the natural resources. [As redesignated from 250.43 at 34 F.R. 13544, Aug. 22, 1969.]

§250.45 Accidents, fires, and malfunctions.

In the conduct of all its operations, the lessee shall take all steps necessary to prevent accidents and fires, and the lessee shall immediately notify the supervisor of all serious accidents and all fires on the lease, and shall submit in writing a full report thereon within 10 days. The lessee shall notify the supervisor within 24 hours of any other unusual condition, problem, or malfunction. [As amended and redesignated from 250.44 at 34 F.R. 13544, Aug. 22, 1969.]

§250.46 Workmanlike operations.

The lessee shall perform all operations in a safe and workmanlike manner and shall maintain equipment for the protection of the lease and its improvements for the health and safety of all persons, and for the preservation and conservation of the property and the environment. The lessee shall take all necessary precautions to prevent and shall immediately remove any hazardous oil and gas accumulations or other health, safety or fire hazards. [As amended and redesignated from 250.45 at 34 F.R. 13544, Aug. 22, 1969.]

§250.47 Sales contracts.

The lessee shall file with the supervisor within 30 days after the effective date thereof copies of all contracts for the disposal of lease products. Nothing in any such contract shall be construed or accepted as modifying any of the provisions of the lease, including provisions relating to gas waste, taking royalty in kind, and the method of computing royalties due as based on a minimum valuation and in accordance with the regulations applicable to the lands covered by the contract. [As amended and redesignated from 250.46 at 34 F.R. 13544, Aug. 22, 1969.]

§250.48 Division orders.

The lessee shall file with the supervisor within 30 days after the effective date thereof copies of division orders or other instruments granting to transportation agencies or purchasers authority to receive products from leased lands. The supervisor may, upon request, approve such orders or other instruments subject to such conditions as he shall prescribe. [As amended and redesignated from 250.47 at 34 F.R. 13544, Aug. 22, 1969.]

§250.49 Royalty and rental payments.

The lessee shall pay all rentals when due and shall pay in value or deliver in production all royalties in the amounts determined by the supervisor as due under the terms of the lease. Payments of rentals and royalties in value shall be by check or draft on a solvent bank, or by money order, drawn to the order of the United States Geological Survey. [As amended at 21 F.R. 4668, June 27, 1956, and redesignated from 250.48 at 34 F.R. 13544, Aug. 22, 1969.]

§250.50 Unit plans, pooling, and drilling agreements.

Section 5(a)(1) of the act authorizes the Secretary in the interest of conservation to provide for unitization, pooling and drilling agreements. Such agreements may be initiated by lessees or where in the interest of conservation they are deemed necessary they may be required by the Director. [Section 3381.1 of 43 CFR is amended and redesignated 250.50 at 34 F.R. 13544, Aug. 22, 1969.]

§250.51 Application for approval of unit plan.

The procedure for obtaining the approval of a unit plan of development is contained in 30 CFR Part 226. "Unit or Cooperative Agreements." All applications to unitize and all documents incident thereto shall be filed in the office of the oil and gas supervisor, Geological Survey, for the geographic area in which the unit is situated. [Section 3381.1 of 43 CFR is amended and redesignated 250.51 at 34 F.R. 13544, Aug. 22, 1969, also, as amended at 38 F.R. 10003, Apr. 23, 1973.]

§250.52 Pooling or drilling agreements.

(a) With the approval of the supervisor, pooling or drilling agreements may be made between lessees for the purposes of (1) utilizing a common drilling platform to develop adjacent or adjoining leases; (2) permitting operators or pipeline companies to enter into contracts involving a number of leases sufficient to justify operations on a large scale for the discovery, development, production or transportation of oil and gas, sulphur, or other minerals and to finance the same; or (3) for other purposes in the interest of conservation.

(b) A contract submitted for approval under these provisions should be filed with the oil and gas supervisor, together with enough copies to permit retention of 5 copies by the Department after approval. Complete details must be furnished in order that the supervisor may have facts upon which to make a definite determination and prescribe the conditions on which the contract is approved. [Section 3381.3 of 43 CFR is amended and redesignated 250.52 at 34 F.R. 13544, Aug. 22, 1969.]

§250.53 Subsurface storage of oil or gas.

(a) In order to avoid waste or to promote conservation of natural resources, and when it can be shown that no undue intereference with operations under existing leases will result, the Director, upon application by the interested parties, may authorize the subsurface storage of oil or gas in the lands of the Outer Continental Shelf, whether or not produced from the Outer Continental Shelf. Such authorization will provide for the payment of such storage fee or rental on the stored oil or gas as may be determined adequate in each case, or, in lieu thereof, for a royalty other than that prescribed in any lease of the area involved when such stored oil or gas is produced in conjunction with oil or gas not previously produced. Any lease of an area used for the storage of oil or gas shall not be deemed to expire during the period of such storage and so long thereafter as oil or gas not previously produced in paying quantities, or drilling or well reworking operations as approved by the Secretary are conducted thereon.

(b) Applications for subsurface storage shall be filed in triplicate with the oil and gas supervisor and shall disclose the ownership of the lands or interests in the lands involved, the parties in interest, including lessees of other mineral interests, the storage fee, rental, or royalty offered to be paid for such storage and all essential information showing the necessity for such storage. Enough copies of the final agreement signed by the parties in interest shall be submitted for the approval of the Director to permit retention of 5 copies by the Department after approval. [Section 3381.4 of 43 CFR is amended and redesignated 250.53 at 34 F.R. 13544, Aug. 22, 1969.]

MEASUREMENT OF PRODUCTION AND COMPUTATION OF ROYALTIES

§250.60 Measurement of oil.

The lessee shall gage and measure all production in accordance with methods approved by the supervisor. The lessee shall provide tanks suitable for measuring accurately the crude oil produced from the lease (test copies of 100 percent capacity tank tables to be furnished to the supervisor) or may arrange with the supervisor for other acceptable methods of measuring, storing, and recording production. The quantity and quality of all production shall be determined in accordance with the standard practices, procedures, and specifications generally used by the industry. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.61 Measurement of gas.

The lessee shall measure all gas production in accordance with methods approved by the supervisor, and the measured volumes shall be adjusted to the standard pressure base of 10 ounces above the atmospheric pressure of 14.4 pounds per square inch, standard temperature of 60° Fahrenheit, and deviation from Boyle's law. If gas is being disposed of at a different pressure base, the supervisor may require that gas volumes be adjusted to conform to such b

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§250.62 Determination of content of gas.

The content of gas delivered to an extraction plant reating gas from the lease shall be determined eriodically by field tests, as required by the upervisor, to be made at the place and by the nethods approved by him and under his supervision.

§250.63 Quantity basis for substances extracted from gas.

(a) The primary quantity basis for computing nonthly royalties on casing-head or natural gasoline, utane, propane, or other substances (hereinafter called ubstances in this section) extracted from gas is the nonthly net output of the plant at which the ubstances are manufactured, “net output” being efined as the quantity of each substance that the lant produces for sale.

(b) If the net output of a plant is derived from the as obtained from only one lease, the quantity of ubstances on which computations of royalty for the ease is based is the net output of the plant.

(c) If the net plant output of a substance is derived om gas obtained from several leases producing gas of niform content of such substance, the proportion of et output of the substance allocable to each lease as a asis for computing royalty will be determined by ividing the amount of gas delivered to the plant from ach lease by the total amount of gas delivered from l leases.

(d) If the net plant output of a substance is derived om gas obtained from several leases producing gas of verse content of such substance, the proportion of et output of the substance allocable to each lease as a asis for computing royalty will be determined by ultiplying the amount of gas delivered to the plant om the lease by the substance content of the gas and viding the arithmetical product thus obtained by the m of the similar arithmetical products separately btained for all leases from which gas is delivered to e plant.

250.64 Value basis for computing royalties.

The value of production, for the purpose of mputing royalty, shall be the estimated reasonable lue of the product as determined by the supervisor, e consideration being given to the highest price paid r a part or for a majority of production of like ality in the same field or area, to the price received the lessee, to posted prices, and to other relevant itters. Under no circumstances shall the value of oduction of any of said substances for the purposes computing royalty be deemed to be less than the ss proceeds accruing to the lessee from the sale ereof or less than the value computed on such isonable unit value as shall have been determined by the Secretary. In the absence of good reason to the contrary, value computed on the basis of the highest price paid or offered at the time of production in a fair and open market for the major portion of like-quality products produced and sold from the field or area where the leased lands are situated will be considered to be a reasonable value.

§250.65 Royalty on oil.

(a) The royalty on crude oil, including condensates separated from gas without the necessity of a manufacturing process, shall be the percentage of the value or amount of the crude oil produced from the leased lands established by law, regulation, or the provisions of the lease. No deduction shall be made for actual or theoretical transportation losses.

(b) Royalty shall be based on production removed from the lease except that, when conditions so warrant, the supervisor may require such royalty to be based on actual monthly production. Evidence of all shipments shall be filed with the supervisor within five days (or such longer period as the supervisor may approve) after the oil has been run by pipeline or by other means of transportation. Such evidence shall be signed by representatives of the lessee and of the purchaser or the transporter who have witnessed the measurements reported, and the determinations of gravity, temperature, and the percentage of impurities contained in the oil shall be shown. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.66 Royalty on unprocessed gas.

If gas, either gas-well gas or casing-head gas, is sold without processing for the recovery of constituent products, the royalty thereon shall be the percentage established by the terms of the lease of the value or amount of the gas produced.

§250.67 Royalty on processed gas and constituent products.

(a) If gas is processed for the recovery of constituent products, a royalty as provided in the lease will accrue on the value or amount of:

(1) All residue gas remaining after processing; and

(2) All natural gasoline, butane, propane, or other products extracted therefrom, subject to deduction of such portion thereof as the supervisor determines to be a reasonable allowance for the cost of processing based upon regional plant practices and costs and other pertinent factors; provided, however, that such reasonable allowance shall not exceed two-thirds of the products extracted unless the Director determines that a greater allowance is in the interest of conservation.

(b) Under no circumstances shall the amount of royalty on the residue gas and extracted products be less than the amount which the supervisor determines would be payable if the gas had been sold without processing.

(c) In determining the value of natural gasoline, the volume of such gasoline shall be adjusted to a standard by a method approved by the supervisor when necessary to adjust volumetric differences between natural gasolines of various specifications.

(d) No allowance shall be made for boosting residue gas or other expenses incidental to marketing.

(e) The lessee, with the approval of the supervisor, may establish a gross value per unit of 1,000 cubic feet of gas on the lease or at the wellhead for the purpose of computing royalty on gas processed for the recovery of constituent products, provided that the royalty shall not be less than that which would accrue by computing royalties in accordance with the provisions of paragraph (a) through (d) of this section. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.68 Commingling production.

Subject to such conditions as he may prescribe for measurement and allocation of production, the supervisor may authorize the lessee to move production from the lease to a central point for purposes of treating, measuring, and storing, and in moving such production, the lessee may commingle the production from different wells, leases, pools, and fields, and with production of other operators. The central point may be on shore or at any other convenient place selected by lessee.

§250.69 Measurement of sulphur.

The measurement of sulphur for the purpose of computing royalty shall be on such basis and shall conform to such standards as the supervisor may approve.

PROCEDURE IN CASE OF DEFAULT BY LESSEE

§250.80 Default.

Whenever the owner of a lease fails to comply with the provisions of the regulations in this part, the supervisor is authorized to give 30-day notice of such default by registered letter to the lessee at his record post office address as provided in section 5(b)(1) of the act and to recommend to the Secretary, through the Director, lease cancellation pursuant to section 5(b)(1) and (2) of the act, appropriate action under the penalty provisions of section 5(a)(2) of the act, or the exercise of such other legal or equitable remedy as the lessor may have.

§250.81 Appeals.

Orders or decisions issued under the regulations in this part may be appealed as provided in part 2[illegible] of this chapter. Compliance with any such order or decision shall not be suspended by reason of any appeal having been taken unless such suspension is authorized in writing by the Director or the Board of Land Appeals (depending upon the official before whom the appeal is pending) and then only upon a determination that such suspension will not be detrimental to the lessor or upon the submission and acceptance of a bond deemed adequate to indemnify the lessor from loss or damage. [As amended at 3[illegible] F.R. 10004, April 23, 1973.]

§250.82 Judicial review.

Nothing contained in this part shall be construed to prevent any interested party from seeking judicial review as authorized by law.

REPORTS TO BE MADE BY ALL LESSEES
(Including Operators)

§250.90 General requirements.

Information required to be submitted in accordance with the regulations in this part shall be furnished in the manner and form prescribed in the regulations in this part or as directed by the supervisor. Copies of forms can be obtained from the supervisor and must be filled out completely and filed punctually with that official.

§250.91 Application for permit to drill, deepen, or plug back.

Applications for permits to drill, deepen, or plug back must be filed in triplicate on Form 9-331C. Prior to commencing such operations approval in writing must be received from the supervisor.

(a) *Application for permit to drill.*

(1) The application must give the surface location and projected bottom-hole location in feet from the lease boundaries; elevation of the derrick floor; water depth; depth to which the well is proposed to be drilled; estimated depths to the top of significant markers; depths at which water, oil, gas, and mineral deposits are expected; the proposed blowout prevention and casing program, including the size, weight, grade, and setting depth of casing, and the quantity of cement to be used, together with all the information specified on Form 9-331C. Information also shall be furnished relative to the proposed plans for drilling other wells from the same platform, for coring at specified depths, and for electrical and [illegible]

logging, together with any other information required by the supervisor.

(2) At least two copies of the application shall be accompanied by: (i) A certified plat drawn to a scale of 2,000 feet to the inch, showing surface and subsurface location of the well to be drilled and all wells theretofore drilled in the vicinity for which information is available, and (ii) information specified in §250.34 to the extent not included in the application or previously furnished (reference must be made thereto).

(b) *Application for permit to deepen or plug back.* The application must describe fully: (1) The present status of the well including the production string or last string of casing, well depth, present productive zones and productive capability, and other pertinent matters; and (2) the details of the proposed work and the necessity therefor. [As amended and renamed at 34 F.R. 13544, Aug. 22, 1969.]

§250.92 Sundry notices and reports on wells.

All notices of intention to fracture treat, acidize, epair, multiple complete, abandon, change plans, and or other similar purposes, and all subsequent reports ertaining to such operations shall be submitted on orm 9-331 in triplicate in accordance with §250.38(b). Prior to commencing such operations pproval must be received from the supervisor in writing.

(a) *Notice of intention to change the condition of a ell.* Form 9-331 shall contain a detailed statement of e proposed work for repairing (other than work icidental to ordinary well operation), acidizing or imulating production by other methods, perforating, detracking, squeezing with mud or cement, or ommencing any operations that will materially change e approved program for drilling a well or alter the ondition of a completed well other than those perations covered by §250.91.

(b) *Subsequent report of changing the condition of well.* Form 9-331 shall contain a detailed report of l work done and the results obtained. The report all set forth the amount and rate of production of l, gas, and water before and after the work was mpleted and shall include a complete statement of e dates on which the work was accomplished and the ethods employed.

(c) *Notice of intention to abandon well.* Form 331 shall contain a detailed statement of the oposed work for abandonment of any well, including drilling well, a depleted producing well, an injection ll, or a dry hole. The statement as to a producible ll shall set forth the reasons for abandonment and e amount and date of last production and, as to all wells, shall describe the proposed work, including kind, location, and length of plugs (by depths), and plans for mudding, cementing, shooting, testing, removing casing, and other pertinent information.

(d) *Subsequent report of abandonment.* Form 9-331 shall contain a detailed report of the manner in which the abandonment or plugging work was accomplished, including the nature and quantities of materials used in plugging and the location and extent (by depths) of casing left in the well; and the volume of mud fluid used. If an attempt was made to part any casing, a description of the methods used and results obtained must be included. [As amended and redesignated from 250.91 at 34 F.R. 13544, Aug. 22, 1969.]

§250.93 Monthly report of operations.

A separate report of operations for each lease must be made on Form 9-152 for each calendar month, beginning with the month in which drilling operations are initiated, and must be filed in duplicate with the supervisor on or before the 20th day of the succeeding month, unless an extension of time for the filing of such report is granted by the supervisor. The report on this form shall disclose accurately all operations conducted on each well during each month, the status of operations on the last day of the month, and a general summary of the status of operations on the leased lands, and the report must be submitted each month until the lease is terminated or until omission of the report is authorized by the supervisor. It is particularly necessary that the report shall show for each calendar month:

(a) Each well listed separately by number and its location shown if possible.

(b) The number of days each well produced whether oil or gas, and the number of days each input well was in operation.

(c) The quantity of oil, gas, and water produced; the total amount of gasoline and other lease products recovered; and other required information. When oil and gas, or oil, gas, and gasoline, or other hydrocarbons are concurrently produced from the same lease, separate reports on this form should be submitted for oil and gas and gasoline, unless otherwise authorized or directed by the supervisor.

(d) The depth of each active or suspended well; the name, character, and depth of each formation drilled during the month; the date each such depth was reached; the date and reason for every shutdown; the names and depths of important formation changes and contents of formations; the amount and size of any casing run since last report; the dates and results of any tests such as production, water shutoff, or gasoline content; and any other noteworthy information on operations not specifically provided for in the form.

(e) If no runs or sales were made during the calendar month, the report must so state.

§250.94 Statement of oil and gas runs and royalties.

When directed by the supervisor, a monthly report shall be made by the lessee in duplicate, on Form 9-153, showing each run of oil; all sales of gas, gasoline, and other lease products; and the royalty accruing therefrom to the lessor. [As amended at 34 F.R. 13544, Aug. 22, 1969.]

§250.95 Well completion or recompletion report and log.

All reports and logs of well completions or recompletions shall be submitted on or attached to Form 9-330 in duplicate in accordance with §250.38(b). The form shall contain a complete and accurate log and report of all operations conducted on the well as specified on the form. Duplicate copies of logs that may have been compiled for geologic information from cores or formation samples shall be filed in addition to the regular log. Geologic markers and all important zones of porosity and contents thereof; cored intervals; and all drill-stem tests, including depth interval tested, cushion used, time tool open, flowing and shut-in pressures, and recoveries shall be shown as provided therefor on Form 9-330 or on attachments thereto. If not previously furnished, duplicate copies of composites of multiple runs of all well bore surveys, including electric, radioactive, sonic and other logs, temperature surveys, and directional surveys shall be attached. (Such copies are in addition to field prints filed pursuant to §250.38(d).) [As amended and redesignated from 250.92 at 34 F.R. 13544, Aug. 22, 1969.]

§250.96 Special forms or reports.

When special forms or reports other than those referred to in the regulations in this part may be necessary, instructions for the filing of such forms or reports will be given by the supervisor. [Redesignated from 250.95 at 34 F.R. 13544, Aug. 22, 1969.]

§250.97 Public inspection of records.

Geological and geophysical interpretations, maps, and data required to be submitted under this part shall not be available for public inspection without e consent of the lessee so long as the lease remain n effect or until such time as the supervisor determi s that release of such information is required d necessary for the proper development of the field r area. [F.R. Doc. 69-10027; Filed Aug. 21, 1969.]

MINERAL LEASES AFFECTED BY SECTION 6 OF OUTER CONTINENTAL SHELF LANDS ACT

§250.100 Effect of regulations on provisions of lea

(a) As contemplated by section 6(b) of the act, t regulations in this part will supersede the provisions any lease which is determined to meet the requi ments of section 6(a) of the act, to the extent th they cover the same subject matter, with the followi exceptions: The provisions of a lease with respect the area covered by the lease, the minerals covered the lease, the rentals payable under the lease, t royalties payable under the lease (subject to t provisions of sections 6(a)(8) and 6(a)(9) of the ac and the term of the lease (subject to the provisions section 6(a)(10) of the act and, as to sulphur, subje to the provisions of section 6(b)(2) of the act) sh continue in effect and, in the event of any conflict inconsistency, shall take precedence over t regulations in this part.

(b) A lease that meets the requirements of secti 6(a) of the act shall also be subject to the mine leasing regulations applicable to the Outer Continent Shelf, as well as the regulations relating to geophysic and geological exploratory operations and to pipeli rights-of-way in the Outer Continental Shelf, to t extent that those regulations are not contrary to inconsistent with the provisions of the lease relating the area covered, the minerals covered, the renta payable, the royalties payable, and the terms of th lease.

NOTE: The record keeping or reportir requirements of this part have been approved by th Bureau of the Budget in accordance with the Feder Reports Act of 1942. [See 43 CFR, Part 3300.]

PART 290 — APPEALS PROCEDURES

ec.
90.1 Scope.
90.2 Who may appeal.
90.3 Appeals to Director.
90.4 Oral argument.
90.5 Time limitations.
90.6 Appeals to the Commissioner of Indian Affairs.
90.7 Appeals to the Board of Land Appeals.

AUTHORITY.—R.S. 463, 25 U.S.C. 2; R.S. 465, 25 .S.C. 9; sec. 32, 41 Stat. 450, 30 U.S.C. 189; sec. 5, 4 Stat. 1058, 30 U.S.C. 285; sec. 10, 61 Stat. 915, 0 U.S.C. 359; sec. 5, 6, 67 Stat. 464, 465, 43 U.S.C. 334, 1335; sec. 24, 84 Stat. 1573, 30 U.S.C. 1023.

290.1 Scope.

The rules and procedures set forth herein apply to ppeals to the Director, Geological Survey (and the ommissioner of Indian Affairs when Indian lands are nvolved) from final orders or decisions of officers of he Conservation Division, Geological Survey, issued nder authority of the regulations in chapter II of this itle, 43 CFR part 23, 43 CFR subtitle B, chapter II, nd 25 CFR part 177. This part also provides for the urther right of appeal to the Board of Land Appeals n the Office of Hearings and Appeals, Office of the ecretary, from adverse decisions of the Director (and he Commissioner of Indian Affairs when Indian lands re involved) rendered under this part.

290.2 Who may appeal.

Any party to a case adversely affected by a final rder or decision of an officer of the Conservation ivision of the Geological Survey shall have a right to ppeal to the Director, Geological Survey, unless the ecision was approved by the Secretary or the Director rior to promulgation.

290.3 Appeals to Director.

(a) An appeal to the Director, Geological Survey, may be taken by filing a notice of appeal in the office f the official issuing the order or decision within 30 ays from service of the order or decision. The notice f appeal shall incorporate or be accompanied by such ritten showing and argument on the facts and laws as the appellant may deem adequate to justify reversal or modification of the order or decision. Within the same 30-day period, the appellant will be permitted to file in the office of the official issuing the order or decision additional statements of reasons and written arguments or briefs.

(b) The officer with whom the appeal is filed shall transmit the appeal and accompanying papers to the Director, Geological Survey, with a full report and his recommendation on the appeal.

(c) The Director will review the record and render a decision in the case.

§290.4 Oral argument.

Oral argument in any case pending before the Director, Geological Survey, will be allowed on motion in the discretion of such officer and at a time to be fixed by him.

§290.5 Time limitations.

With the exception of the time fixed for filing a notice of appeal, the time for filing any document in connection with an appeal may be extended by the Director, Geological Survey. A request for an extension of time must be filed within the time allowed for filing of the document and must be filed in the same office in which the document in connection with which the extension is requested must be filed.

§290.6 Appeals to the Commissioner of Indian Affairs.

The procedure for appeals under this part shall be followed for permits and leases on Indian land except that with respect to such permits and leases, the Commissioner of Indian Affairs will exercise the functions vested in the Director, Geological Survey.

§290.7 Appeals to the Board of Land Appeals.

Any party to a case adversely affected by a final decision of the Director, Geological Survey, or the Commissioner of Indian Affairs under this part shall have a right of appeal to the Board of Land Appeals in the Office of Hearings and Appeals, Office of the Secretary, in accordance with the procedures provided in 43 CFR, "Part 4, Department Hearings and Appeals Procedures." [38 F.R. 10,004, April 23, 1973.]

REGULATIONS PERTAINING TO
MINERAL LEASING
ON THE
OUTER CONTINENTAL SHELF

as contained in

TITLE 43 of the CODE of
FEDERAL REGULATIONS

Group 3300 — Outer Continental Shelf Leasing

PART 3300 — OUTER CONTINENTAL SHELF LEASING; GENERAL

Subpart 3300 — Outer Continental Shelf Mineral Deposits; General

S
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00.0-4 Applicability of public land laws.
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00.3 Helium.
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SUBPART 3300 — OUTER CONTINENTAL SHELF MINERAL DEPOSITS; GENERAL

§3300.0-3 Purpose and authority.

The Outer Continental Shelf Lands Act of August 7, 1953 (67 Stat. 462; 43 U.S.C. §1331 et seq.), referred to in this part as "the act," among other things, authorizes the Secretary of the Interior to issue on a competitive basis leases for oil and gas, sulphur, and other minerals in submerged lands of the Outer Continental Shelf, as defined in section 2 of the act. Subject to the supervisory authority of the Secretary, the regulations in this part shall be administered by the Director, Bureau of Land Management, hereinafter referred to in this part as the Director.

§3300.0-4 Applicability of public land laws.

The laws and regulations pertaining to the public lands of the United States are not applicable to the submerged lands of the Outer Continental Shelf. Mineral deposits in the submerged lands of the Outer Continental Shelf are subject to disposition only in accordance with the provisions of the act and the regulations promulgated by the Secretary thereunder.

§3300.1 Persons qualified to hold leases.

Mineral leases issued pursuant to section 8 of the act may be held only by citizens of the United States over 21 years of age, associations of such citizens, States, political subdivisions of a State, or private, public, or municipal corporations organized under the laws of the United States or of any State or Territory thereof.

§3300.3 Helium.

Each lease issued or continued under the act shall be subject to a reservation by the United States of the ownership of and the right to extract helium from all gas produced from the leased area, subject to such rules and regulations as shall be prescribed by the Secretary of the Interior. In case the United States elects to take the helium, the lessee shall deliver all gas containing helium, or the portion of gas desired, to the United States at any point on the leased area in the manner required by the United States, for the extraction of helium in such plant or reduction works for that purpose as the United States may provide, whereupon the residue shall be returned to the lessee with no substantial delay in the delivery of gas produced from the well to the purchaser thereof. The lessee shall not suffer a diminution of value of the gas from which the helium has been extracted, or loss otherwise, for which he is not reasonably compensated, save for the value of the helium extracted. The United States shall have the right to erect, maintain, and operate on the leased area any and all reduction works and other equipment necessary for the extraction of helium.

§3300.4 Payments of filing charges, bonuses, rentals and royalties.

All payments to the United States required by the act or the regulations in this part shall be made to the oil and gas supervisor of the Geological Survey for the region in which the leased area is situated, except that payments of filing charges, bonuses and first year's rental shall be made to the manager of the appropriate field office, Bureau of Land Management, unless otherwise directed by the Secretary. All payments should be made by check, bank draft, or money order payable to the United States Geological Survey, if the payments are made to the Geological Survey, or to the Bureau of Land Management, if the payments are made to that Bureau.

Subpart 3301 – Leasing Areas

§3301.1 Leasing maps.

(a) Any area of the Outer Continental Shelf which has been appropriately platted as provided in paragraph (b) of this section is subject to lease for any mineral not included in a subsisting lease issued under the act or meeting the requirements of subsection (a) of section 6 of the act, unless before any lease is offered or issued the unit is (1) withdrawn from disposition pursuant to section 12(a) of the act, or (2) designated as an area or part of an area restricted from operation under section 12(d) of the act.

(b) As the need arises, the Bureau of Land Management will prepare official leasing maps of areas of the Outer Continental Shelf, which will be made to conform so far as practicable to the method of tract designation established by the adjoining State. The area included in each mineral lease shall be described in accordance with the official leasing map.

§3301.2 Resources evaluation.

From time to time the Director may announce tentative schedules of lease sales of Outer Continental Shelf areas. At such time as an area is initially considered for mineral leasing, or as the need arises the Director shall request the Geological Survey to prepare a summary report describing the general geology and potential mineral resources of the area and shall request other interested Federal agencies to prepare reports describing to the extent known any other valuable resources contained within the general area and the potential effect of mineral operations upon the resources or upon the total environment.

§3301.3 Nominations of tracts.

In selecting tracts for oil and gas, sulphur, or other mineral leasing, the Director will receive and consider nominations of tracts or requests describing areas and expressing an interest in leasing of minerals, or, from time to time, upon his own motion, upon approval of the Secretary, may issue calls for nominations of tracts for the leasing of minerals in specified areas. Nominations of tracts should be addressed to the Director, with copies to the appropriate Bureau of Land Management field office and the appropriate oil and gas supervisor of the Geological Survey. The Director, Geological Survey, shall submit recommendations to the Director on tract selections and lease terms and conditions.

§3301.4 Selection of tracts.

The Director, prior to the final selection of tracts for leasing, either selected on his own motion or nominated pursuant to §3301.3 of this subpart, shall evaluate fully the potential effect of the leasing program on the total environment, aquatic resources, aesthetics, recreation, and other resources in the entire area during exploration, development and operational phases. To aid him in his evaluation and determinations he shall request and consider the views and recommendations of appropriate Federal agencies, may hold public hearings after appropriate notice, and may consult with State agencies, organizations, industry and individuals. The Director shall develop special leasing stipulations and conditions when necessary to protect the environment and all other resources, and such special stipulations and conditions shall be contained in the proposed notice of lease offer. The proposed notice of lease offer, together with all views and recommendations received and the Director's findings or actions thereon, shall be submitted to the Secretary for final approval.

§3301.5 Notice of lease offer.

Upon approval of the Secretary, the Director shall ublish the notice of lease offer at the expense of the Jnited States in the *Federal Register*, as the official ublication, and in other publications as may be lesirable. The publication in the *Federal Register* shall e at least 30 days prior to the date of the sale. The otice shall state the place and time at which bids will e filed, and the place, date, and hour at which bids vill be opened. The notice shall contain any special ipulations or conditions which will become a part of ny lease issued pursuant to such notice, including ipulations or conditions for the protection of the nvironment, aquatic life and other resources.

3301.6 Tracts subject to drainage.

Upon direction of the Secretary, the Director, after otaining the recommendation of the Director, eological Survey, is authorized to publish on his own otion notices of lease offer of tracts which have been termined by the Director, Geological Survey, to be bject to drainage of their oil and gas deposits from ells on other tracts. The Director may request and nsider the views and recommendations of propriate Federal and State agencies prior to blishing the notice of lease offer. The notice shall be blished in accordance with section 3301.5 of this subpart.

Subpart 3302 — Issuance of Leases

§302.1 General.

Tracts will be offered for lease by competitive sealed bidding under conditions specified in the notice of lease offer. Each oil and gas lease issued pursuant to section 8 of the act shall cover a compact area not exceeding 5,760 acres.

§302.2 Term.

a) All oil and gas leases shall be issued for a term of 5 years and so long thereafter as oil or gas may be produced from the leasehold in paying quantities, or drilling or well reworking operations, as approved by the Secretary under §3305a.1 of this part, are conducted thereon.

b) All sulphur leases shall be issued for a term of 10 years and so long thereafter as sulphur may be produced from the leasehold in paying quantities or drilling, well reworking, plant construction, or other operations for the production of sulphur, as approved by the Secretary, are conducted thereon.

(c) Other mineral leases shall be issued for such terms as may be prescribed at the time of offering the leases in the notice of lease offer.

§3302.4 What must accompany bids.

(a) A separate bid must be submitted for each lease unit described in the notice of lease offer. A bid may not be submitted for less than an entire unit. Each bidder must submit with his bid a certified or cashier's check or bank draft on a solvent bank, or a money order or cash, for one-fifth of the amount of the cash bonus. If the bidder is an individual, he must submit with his bid a statement of his citizenship. If the bidder is an association (including a partnership), the bid shall be accompanied also by a certified copy of the articles of association or appropriate reference to the record of the Bureau of Land Management in which such a copy has already been filed, with a statement as to any subsequent amendments. If the bidder is a corporation, the following additional information shall be submitted with the bid.

(1) A certified copy of the articles of incorporation and a copy either of the minutes of the meeting of the board of directors or of the by-laws indicating that the person signing the bid has authority to do so, or, in lieu of such a copy, a certificate by the secretary or the assistant secretary of the corporation to that effect, over the corporate seal or appropriate reference to the record of the Bureau of Land Management in connection with which such articles and authority have been previously furnished.

(b) All bidders are warned against violation of the provisions of Title 18 U.S.C. section 1860, prohibiting unlawful combination or intimidation of bidders.

§3302.5 Award of lease.

Sealed bids received in response to the notice of lease offer shall be opened at the place, date and hour specified in the notice. The opening of bids is for the sole purpose of publicly announcing and recording the bids received and no bids will be accepted or rejected at that time. In accordance with section 8 of the act, leases will be awarded only to the highest responsible qualified bidder. The United States reserves the right and discretion to reject any and all bids received for any tract, regardless of the amount offered. Awards of leases will be made only by written notice from the authorized officer. Such notices shall transmit the lease forms for execution. In the event the highest bids are tie bids, tie bidders may file with the Director within 15 days after notification an agreement to accept the lease jointly, otherwise all bids will be rejected. If the authorized officer fails to accept the highest bid for a lease within 30 days after the date on which the bids are opened, all bids for such lease will be considered rejected. Notice of his action will be transmitted promptly to the several bidders. If the lease is awarded, three copies of the lease will be sent to the successful bidder and he will be required not later than the 15th day after his receipt thereof, or the 30th day after the date of the sale, whichever is later, to execute them, pay the first year's rental, the balance of the bonus bid, and file a bond as required in §3304.1. Deposits on rejected bids will be returned. If the successful bidder fails to execute the lease or otherwise comply with the applicable regulations, his deposit will be forfeited and disposed of as other receipts under the act. If before the lease is executed on behalf of the United States the land is withdrawn or restricted from leasing, all payments made by the bidder will be refunded. If the awarded lease is executed by an agent acting in behalf of the bidder, the lease must be accompanied by evidence that the bidder authorized the agent to execute the lease. When the three copies of the lease are executed by the successful bidder and returned to the authorized officer, the lease will be executed on behalf of the United States, and one fully executed copy will be mailed to the successful bidder.

§3302.6 Form.

Oil and gas leases and leases for sulphur will be issued on forms approved by the Director. Other mineral leases will be issued on such forms as may be prescribed by the Secretary.

§3302.7 Dating of leases.

All leases issued under the regulations in this part will be dated and become effective as of the first day of the month following the date the leases are signed on behalf of the lessor, except that, when prior written request is made, a lease may be dated and become effective as of the first day of the month within which it is so signed.

Subpart 3303 — Rentals and Royalties

§3303.1 Rentals.

An annual rental shall be due and payable in advance on the first day of each lease year prior to discovery at the rate specified in the lease. The owner of any lease created by the assignment of a portion of a producing lease and on which assigned portion there is no discovery shall be required to pay an annual rental for such assigned portion at the rate per acre specified in the lease payable each lease year following the year in which the assignment became effective and prior to a discovery on such segregated portion.

§3303.2 Royalties.

Royalties shall be at the rate specified in the lease but in no event shall the royalty on oil and gas be less than 12 1/2 percent of the amount or value of the production saved, removed or sold from the lease nor on sulphur less than 5 percent of the gross production of value of the sulphur at the wellhead.

§3303.3 Minimum royalty.

Each lessee shall pay the minimum royalty specified in the lease at the end of each lease year beginning with the first lease year following a discovery on the lease.

§3303.5 Effect of suspensions on royalty and rental.

(a) In the event that under the provisions of 30 CFR 250.12(c) or (d)(1) the regional oil and gas supervisor of the Geological Survey with respect to any lease directs the suspension of both operations and production, or with respect to a lease on which there is no producible well directs the suspension of operations, no payment of rental or minimum royalty will be required for or during the period of the suspension. In the event that under the provision of 30 CFR 250.12(d)(1) the supervisor approves, at the request of a lessee, the suspension of operation or production, or both, or under the provisions of 30 CFR 250.12(d)(3) suspends any operation including production, the lessee will not be relieved of the obligation to pay rental, minimum royalty or royalty for or during the period of suspension.

(b) In the event the anniversary date of a lease falls within a period of suspension for which no rental or minimum royalty payments are required under paragraph (a), of this section, the prorated rental or minimum royalties, if any are due and payable as of the date the suspension period terminates, shall be computed and notice thereof given the lessee. Payment of the amount due shall be made by the lessee within 30 days after receipt of such notice. The anniversary date of a lease will not change by reason of any period of lease suspension or rental or royalty relief resulting therefrom.

Subpart 3304 — Bonds

§3304.1 Amount of bond required of lessee.

The successful bidder prior to the issuance of an oil and gas or sulphur lease must furnish a corporate surety bond in the sum of $50,000 conditioned on compliance with all of the terms of the lease, unless he already maintains or furnishes a bond in the sum of $300,000 conditioned on compliance with the terms of oil and gas and sulphur leases held by him on the Outer Continental Shelf in the (a) Gulf of Mexico, (b) along the Pacific Coast, or (c) along the Atlantic Coast, as may be appropriate. An operator's bond in the same amount may be substituted at any time for the lessee's bond. The United States reserves the right to require additional security in the form of

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pplemental bond or bonds or to increase the verage of an existing bond if, after operations or oduction have begun, such additional security is emed necessary. The amount of bond coverage on ses for other minerals will be determined at the time the offer to lease and will be stated in the notice of ease offer. Where upon a default, the surety on an ter Continental Shelf Mineral Lease Bond makes yment to the Government of any indebtedness under ease secured thereby, the face amount of such bond d the surety's liability thereunder shall be reduced the amount of such payment. Thereafter, upon nalty of cancellation of all of the leases covered by h bond, the principal shall post a new bond, on a m approved by the Director, in the amount of 0,000 within 6 months after notice, or within such rter period as the authorized officer of the Bureau Land Management may fix. However, in lieu reof, the principal may within that time file arate bonds for each lease. The provisions hereof y be made applicable to any bond in force at the e of the approval of the amendment of this section filing in the local office of the Bureau of Land nagement, a written consent to that effect and an eement to be bound by the provisions hereof cuted by the principal and surety. Upon receipt reof the bond will be deemed to be subject to the visions of this section.

§304.2 Form of bond.

Bonds furnished by lessee or operator for a single le e will be on forms approved by the Director. The $0,000 bond will be on a form approved by the D ector.

Subpart 3305 — Assignment or Transfers

§305.1 Assignment of leases or interest therein.

eases, or any undivided interest therein, may be as ned in whole or as to any officially designated su division subject to the approval of the authorized of cer, to any one qualified under §3380.1 to take ar hold a lease. Any assignment made under this se ion shall, upon approval, be deemed to be effective or nd after the first day of the lease month following it filing in the appropriate office of the Bureau of La d Management, unless at the request of the parties an earlier date is specified in the Director's approval. Th assignor shall be liable for all obligations under the le accruing prior to the approval of the assignment.

§05.2 Requirements for filing of transfers.

)(1) All instruments of transfer of a lease or of an in rest therein, including operating agreements, su eases, and assignments of record interests, must be fil in triplicate for approval within 90 days from the da of final execution with a statement over the tra feree's own signature with respect to citizenship an qualifications similar to that required of a lessee and must contain all of the terms and conditions agreed upon by the parties thereto. Carried working interests, overriding royalty interests, or payments out of production, may be created or transferred without requirement for filing or approval.

(2) An application for approval of any instrument required to be filed must be accompanied by a fee of $10, and an application not accompanied by payment of such a fee will not be accepted for filing. Such fee will not be returned even though the application later be withdrawn or rejected in whole or in part.

(b) Where an attorney in fact, in behalf of the holder of a lease, operating agreement or sublease signs an assignment of the agreement, lease, or interest, or signs the application for approval, there must be furnished evidence of the authority of the attorney in fact to execute the assignment or application and the statement required by §3302.4.

(c) Where an assignment creates a segregated lease a bond must be furnished in the amount prescribed in §3304.1. Where an assignment does not create separate leases the assignee, if the assignment so provides and the surety consents, may become a joint principal on the bond with the assignor.

(d) In order for the heirs or devisees of a deceased holder of a lease, or any interest therein, to be recognized by the Department as the lawful successor to such lease or interest, evidence of their status as such heirs or devisees must be furnished in the form of a certified copy of an appropriate order or decree of the court having jurisdiction of the distribution of the estate or, if no court action is necessary, the statements of two disinterested parties having knowledge of the facts or a certified copy of the will, and, in all cases, the statements of the heirs or devisees that they are the persons named as successors to the estate with evidence of their qualifications as provided in §3302.4. In the event such heirs or devisees are unable to qualify to hold the lease or interest they will nevertheless be recognized as the lawful successors of the deceased for a period of not to exceed 2 years from the date of death of their predecessor in interest.

§3305.3 Separate assignments required for transfer of record title to leases.

A separate instrument of assignment must be filed for each lease when transfers involve record titles. When transfers to the same person, association, or corporation, involving more than one lease are filed at the same time for approval, one request for approval and one showing as to the qualifications of the assignee will be sufficient.

§3305.4 Effect of assignment of particular tract.

(a) When an assignment is made of all of the record title to a portion of the acreage in a lease, the assigned and retained portions become segregated into separate and distinct leases. The assignee becomes a lessee of the Government as to the segregated tract and is bound by the terms of the lease as though he had obtained the lease from the United States in his own name, and the assignment after its approval will be the basis of a new record. Royalty, minimum royalty, and rental provisions of the original lease shall apply separately to each segregated portion.

(b) In the case of an assignment of a portion of an oil and gas lease the segregated leases shall continue in full force and effect for the primary term of the original lease and so long thereafter as oil or gas may be produced from the original leased area in paying quantities or drilling or well reworking operations as approved by the Secretary are conducted thereon.

Subpart 3305a — Extension of Leases

§3305a.1 Extension of leases by drilling or well reworking operations.

(a) The Secretary shall be deemed to have approved, within the meaning of section 8(b)(2) of the Outer Continental Shelf Lands Act, drilling or well reworking operations, conducted on the leased area in the following instances:

(1) If, any discovery of oil or gas in paying quantities has been made on the leasehold, and within 90 days prior to expiration of the 5-year term or any extension thereof, or thereafter, the production thereof shall cease at any time, or from time to time, from any cause and production is restored or drilling or well reworking operations are commenced within 90 days thereafter, and such drilling or well reworking operations (whether on the same or different wells) are prosecuted diligently until production is restored in paying quantities.

(2) If, within 90 days prior to expiration of the 5-year term or any extension thereof, or thereafter, at any time, or from time to time, lessee is engaged in drilling or well reworking operations on the leasehold and there is no well on the leasehold capable of producing in paying quantities and the lessee diligently prosecutes such operations (whether on the same or different wells) with no cessation of more than 90 days.

(b) The Secretary may approve such other operations for drilling or reworking upon application of lessee.

(c) Nothing in this section obviates the necessity of obtaining the Oil and Gas Supervisor's approval of a plan or notice of intention to drill or of complying with the provisions of 30 CFR Part 250.

§3305a.2 Directional drilling.

A lease may be maintained in force by directi al wells drilled under the leased area from su ce locations on adjacent or adjoining land not covere by the lease. In such circumstances, drilling shall be considered to have commenced on the leased ea when drilling is commenced on the adjacent or adjoining land for the purpose of directionally dri g under the leased area through any directional ll surfaced on adjacent or adjoining land, and product n, drilling, or reworking of any such directional well ll be considered production or drilling or rework g operations (as the case may be) on the leased area r all purposes of the lease.

§3305a.3 Compensatory payments.

In the event that an oil and gas lessee ma s compensatory payments as provided in 30 CFR 250 3 and in the event that the lease is not being maintai d in force by other production of oil or gas in pay g quantities or by other approved drilling or rework g operations, such payments shall be considered as e equivalent of production in paying quantities for l purposes of the lease.

§3305a.4 Effect of suspensions on lease term.

In the event that under the provisions of 30 C 250.12(c) or (d)(1), the regional Oil and G Supervisor of the Geological Survey directs t suspension of either operations or production, or bo with respect to any lease, the term of the lease will extended by a period equivalent to the period of t suspension. In the event that under the provisions 30 CFR 250.12(c) or (d)(1), the supervisor approv the suspension of either operations or production, both, with respect to any lease, the term of the lea will not be deemed to expire so long as the suspensio remains in effect.

Subpart 3306 — Termination of Leases

§3306.1 Relinquishment of leases or parts of leases.

A lease or any officially designated subdivisio thereof may be surrendered by the record title holde by filing a written relinquishment, in triplicate, wit the appropriate office of the Bureau of Lan Management. A relinquishment shall take effect on th date it is filed subject to the continued obligation o the lessee and his surety to make payment of al accrued rentals and royalties and to abandon all well on the land to be relinquished to the satisfaction o the Oil and Gas Supervisor.

§3306.2 Cancellation of leases.

Any nonproducing lease issued under the act may be canceled by the authorized officer whenever the ssee fails to comply with any provision of the act or lease or applicable regulations in force and effect on the date of the issuance of the lease, if such failure to comply continues for 30 days after mailing of notice by registered letter to the lease owner at his record post office address. Any such cancellation is subject to judicial review as provided in section 8(j) of the act upon the complaint of any person. Producing leases issued under the act may be canceled for such failure only by judicial proceedings in the manner prescribed in section 5(b)(2) of the act. Any lease issued under the act, whether producing or not, will be canceled by the authorized officer upon proof that it was obtained by fraud or misrepresentation, and after notice and opportunity to be heard has been afforded to the lessee.

Subpart 3307 -- Mineral Deposits Affected by Section 6 of Outer Continental Shelf Lands Act

§3307.1 Effect of regulations on provisions of lease.

(a) As contemplated by section 6(b) of the act, the preceding regulations in this part so far as they are applicable and the following regulations will supersede the provisions of any lease which is determined to meet the requirements of section 6(a) of the act, to the extent that they cover the same subject matter, with the following exceptions: The provisions of a lease with respect to the area covered by the lease, the minerals covered by the lease, the rentals payable under the lease, the royalties payable under the lease (subject to the provisions of sections 6(a)(8) and 6(a)(9) of the act), and the term of the lease (subject to the provisions of section 6(a)(10) of the act and, as to sulphur, subject to the provisions of section 6(b)(2) of the act) shall continue in effect and, in the event of any conflict or inconsistency, shall take precedence over those regulations.

(b) A lease that meets the requirements of section 6(a) of the act shall also be subject to all operating and conservation regulations applicable to the Outer Continental Shelf, as well as the regulations relating to geophysical and geological exploratory operations and to pipeline rights-of-way in the Outer Continental Shelf, to the extent that those regulations are not contrary to or inconsistent with the provisions of the lease relating to the area covered, the minerals covered, the rentals payable, the royalties payable, and the term of the lease. Nothing herein should be construed to require compliance with any provision of any State lease the subject matter of which is not covered in the regulations in this part.

§3307.2 Leases of other minerals.

The existence of a lease that meets the requirements of section 6(a) of the act will not preclude the issuance of other leases of the same area for deposits of other minerals: *Provided*, That no lease of minerals other than those covered by the lease shall authorize or permit the lessee thereunder unreasonably to interfere with or endanger operations under the existing lease: *And provided further*, That no sulphur leases will be granted by the United States on any area while such area is included in a lease covering sulphur under section 6(b) of the act.

§3307.3 Obligations of lessee.

§3307.3-1 Bonds.

Within 30 days from the effective date of the regulations in this part or within such further period or periods as may be fixed from time to time by the authorized officer, the lessee under a lease meeting the requirements of section 6(a) of the act must furnish a bond as provided in §3304.1.

§3307.3-2 Wells.

(a) After due notice in writing, the lessee shall drill and produce such wells as the Secretary may reasonably require in order that the leased area or any part thereof may be properly and timely developed and produced in accordance with good operating practice.

(b) At the election of the lessee, the lessee may drill and produce other wells in conformity with any system of well spacing or production allotments affecting the area, field, or pool in which the leased area or any part thereof is situated, which is authorized or sanctioned by applicable law or by the Secretary.

(c) The lessee shall drill and produce such wells as are necessary to protect the lessor from loss by reason of production on other properties, or in lieu thereof, with the consent of the Oil and Gas Supervisor, to pay a sum determined by the supervisor as adequate to compensate the lessor for failure to drill and produce any such well. In the event that this lease is not being maintained in force by other production of oil or gas in paying quantities or by other approved drilling or reworking operations, such payments shall be considered as the equivalent of production in paying quantities for all purposes of this lease.

§3307.3-3 Inspection.

The lessee shall keep open at all reasonable times for the inspection of any duly authorized officer of the Department of the Interior, the leased area and all wells, improvements, machinery and fixtures thereon and all books, accounts, maps and records relative to operations and surveys or investigations on or with regard to the leased area or under the lease.

§3307.3-4 Diligence; compliance with regulations and orders.

The lessee shall exercise reasonable diligence in drilling and producing the wells herein provided for;

shall carry on all operations in accordance with approved methods and practices including those provided in the operating and conservation regulations for the Outer Continental Shelf; shall remove all structures when no longer required for operations under the lease to sufficient depth beneath the surface of the waters to prevent them from being a hazard to navigation and the fishing industry; and shall carry out at expense of the lessee all lawful and reasonable orders of the lessor relative to the matters in this section. On failure of the lessee so to do the lessor shall have the right to enter on the property and to accomplish the purpose of such orders at the lessee's cost: *Provided*, That the lessee shall not be held responsible for delays or casualties occasioned by causes beyond the lessee's control.

§3307.3-5 Freedom of purchase.

The lessee shall accord all workmen and employees directly engaged in any of the operations under the lease complete freedom of purchase.

§3307.3-6 Removal of property on termination of lease.

Upon the expiration of any lease, or the earlier termination thereof as provided in the regulations in this part, the lessee shall within a period of one year thereafter remove from the premises all structures, machinery, equipment, tools, and materials other than improvements needed for producing wells or for drilling or producing other leases, and other property permitted by the lessor to be maintained.

§3307.4 Exploration and operations.

§3307.4-1 Purchase of production.

In time of war, or when the President of the United States shall so prescribe, the United States shall have the right of first refusal to purchase at the market price all or any portion of the oil or gas produced from the leased area, as provided in section 12(b) of the act.

§3307.4-2 Suspension of operations during war or national emergency.

Upon recommendation of the Secretary of Defense, during a state of war or national emergency declared by the Congress or the President of the United States after August 7, 1953, the Secretary is authorized to suspend any or all operations under a lease, as provided in section 12(c) of the act: *Provided*, That just compensation shall be paid by the United States to the lessee whose operations are thus suspended.

§3307.4-3 Restriction of exploration and operations.

The United States shall have the right, as provided in section 12(d) of the act, to restrict from exploration and operations the leased area or any part ther which may be designated by and through the Secret of Defense, with the approval of the President of United States, as, or as part of, an area of the O Continental Shelf needed for national defense. So l as such designation remains in effect no exploratior operations may be conducted on the surface of leased area or the part thereof included within designation except with the concurrence of Secretary of Defense. If operations or product under any lease within any such restricted area shall suspended, any payments of rentals, minimum royal and royalty prescribed by such lease likewise shall suspended during such period of suspension operations and production, and the term of such le shall be extended by adding thereto any su suspension period, and the United States shall be lia to the lessee for such compensation as is required be paid under the Constitution of the United States.

§3307.4-4 Geological and geophysical exploratic rights-of-way.

The United States reserves the right to authorize t conduct of geological and geophysical exploration the leased area which does not interfere with endanger actual operations under the lease and t right to grant such easements or rights-of-way, upc through, or in the leased area as may be necessary appropriate to the working of other lands containi the deposits described in the act, and to the treatme and shipment of products thereof by or unc authority of the Government, its lessees or permitte and for other public purposes, subject to the provisio of section 5(c) of the act where they are applical and to all lawful and reasonable regulations a conditions prescribed by the Secretary thereunder.

§3307.4-5 Leases of sulphur and other mineral.

The United States reserves the right to grant sulph leases and leases of any mineral other than oil, gas, a sulphur within the leased area or any part therec subject to the provisions of sections 8(c), 8(d), a 8(e) of the act and all lawful and reasonable reg lations prescribed by the Secretary thereunder: *Pr vided*, That no such sulphur lease or lease of oth mineral shall authorize or permit the lessee thereund unreasonably to interfere with or endanger operatio under the lease which is continued under section 6 the act.

§3307.5 Remedies in case of default.

(a) Whenever the lessee fails to comply with any the provisions of the act or of the lease or of th lawful and reasonable regulations issued within 90 day after the authorized officer has determined that th lease meets the requirements of section 6(a) of the ac the lease shall be subject to cancellation as follows:

(1) If, at the time of such default, no well is roducing, or is capable of producing, oil or gas in aying quantities from the leased area, whether such ell be drilled from a surface location within the ased area or be directionally drilled from a surface ocation on adjacent or adjoining lands the lease may e canceled by the Secretary (subject to the right of dicial review as provided in section 8(j) of the act) if ch default continues for the period of 30 days after ailing of notice by registered letter to the lessee at e lessee's record post office address.

(2) If, at the time of such default, any well is roducing, or is capable of producing, oil or gas in aying quantities from the leased area, whether such ell be drilled from a surface location within the ased area or be directionally drilled from a surface ocation on adjacent or adjoining lands, the lease may e canceled by an appropriate proceeding in any nited States district court having jurisdiction under e provisions of section 4(b) of the act if such default ontinues for the period of 30 days after mailing of otice by registered letter to the lessee at the lessee's ecord post office address.

(b) If any such default continues for the period of 30 days after mailing of notice by registered letter to the lessee at the lessee's record post office address, the lessor may then exercise any legal or equitable remedy which the lessor may have; however, the remedy of cancellation of the lease may be exercised only under the conditions and subject to the limitations set out in paragraph (a) of this section, or pursuant to section 8(i) of the act.

(c) A waiver of any particular default shall not prevent the cancellation of the lease or the exercise of any other remedy the lessor may have by reason of any other cause or for the same cause occurring at any other time.

§3307.6 Heirs and successors in interest.

Each obligation under any lease and under the regulations in this part shall extend to and be binding upon, and every benefit thereunder shall inure to, the heirs, executors, administrators, successors, or assigns of the lessee.

ATTACHMENT B

T. Jennings

Notice to Lessees and Operators Of Federal

Oil, Gas, And Sulphur Leases
In The Outer Continental Shelf
Gulf Of Mexico Area

OCS Order Nos. 1 through 12—Gulf of Mexico

March 3, 1849

UNITED STATES
DEPARTMENT OF THE INTERIOR

GEOLOGICAL SURVEY
CONSERVATION DIVISION
Branch Of Oil and Gas Operations
Gulf Of Mexico Area

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OCS Order No. 1
August 28, 1969

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

MARKING OF WELLS, PLATFORMS, AND FIXED STRUCTURES

his Order is established pursuant to the authority prescribed in 0 CFR 250.11 and in accordance with 30 CFR 250.37. Section 250.37 rovides as follows:

> Well designations. The lessee shall mark promptly each drilling platform or structure in a conspicuous place, showing his name or the name of the operator, the serial number of the lease, the identification of the wells, and shall take all necessary means and precautions to preserve these markings.

he operator shall comply with the following requirements. Any epartures from the requirements specified in this Order must be pproved pursuant to 30 CFR 250.12(b).

1. Identification of Platforms, Fixed Structures. Platforms and structures, other than individual wellhead structures and small structures, shall be identified at two diagonal corners of the platform or structure by a sign with letters and figures not less than 12 inches in height with the following information: The name of lease operator, the name of the area, the block number of the area in which the platform or structure is located, and the platform or structure designation. The information shall be abbreviated as in the following example:

   "The Blank Oil Company operates 'C' platform in Block 37 of South Timbalier Area."

   The identifying sign on the platform would show:

   "BOC - S.T. - 37 - C."

2. Identification of Single Well Structures and Small Structures. Single well and small structures may be identified with one sign only, with letters and figures not less than 3 inches in

height. The information shall be abbreviated as in the following example:

> "The Blank Oil Company operates well No. 1 which is equipped with a protective structure, in Block 68 in the East Cameron Area."

The identifying sign on the protective structure would show:

> "BOC - E.C. - 68 - No. 1"

3. *Identification of Wells*. The OCS lease and well number shall be painted on, or a sign affixed to, each singly completed well. In multiple completed wells each completion shall be individually identified at the well head. All identifying signs shall be maintained in a legible condition.

Robert F. Evans
Supervisor

Approved: August 28, 1969

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

OCS Order No. 2
August 28, 1969

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

DRILLING PROCEDURES OFF LOUISIANA AND TEXAS

his Order is established pursuant to the authority prescribed in 30 CFR
50.11 and in accordance with 30 CFR 250.34, 250.41 and 250.91. All
xploratory wells drilled for oil and gas shall be drilled in accordance
ith the provisions of this Order. Initial development wells drilled
or oil and gas shall be drilled in accordance with the provisions of
his Order which shall continue in effect until field rules are issued.
fter field rules have been established by the supervisor, development
ells shall be drilled in accordance with such rules; except that in
ields containing more than five development wells, additional develop-
ent wells commenced prior to October 1, 1969, may be excluded from
rovisions of this Order, as approved by the supervisor, to permit time
or the establishment of field rules.

here sufficient geologic and engineering information is obtained through
xploratory drilling, operators may make application to the supervisor
or the establishment of field rules, but the operator(s) shall make such
pplication before more than five development wells have been drilled in
he field. Operators may also make application for the establishment of
ield rules for existing fields containing more than five development
ells on the date of this Order. Each Application to Drill (Form 9-331C)
or exploratory wells and development wells not covered by field rules
hall include all information required under 30 CFR 250.91 and the inte-
rated casing, cementing, mud, and blowout prevention program for the
ell, and shall comply with the following requirements. Any departures
rom the requirements specified in this Order must be approved pursuant
o 30 CFR 250.12(b).

1. Well Casing and Cementing. All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1). The Application to Drill (Form 9-331C) shall contain a statement that all zones which contain oil, gas, or fresh water shall be fully protected by casing and cement. For the purpose of this Order, the several casing strings in order of normal installation are drive or structural casing, conductor casing, surface casing, intermediate casing, and production casing. All depths refer to true vertical depth (TVD).

A. Drive or Structural Casing. This casing shall be set by drilling, driving, or jetting to a minimum depth of 100 feet below the Gulf floor or to such greater depth required to support unconsolidated deposits and to provide hole stability for initial drilling operations. If drilled in, the drilling fluid shall be a type that will not pollute the Gulf, and a quantity of cement sufficient to fill the annular space back to the Gulf floor must be used.

B. Conductor and Surface Casing - General Principles. Determination of proper casing setting depths shall be based upon all geologic factors including the presence or absence of hydrocarbons and water depths on a well-for-well basis. The setting depths of all casing strings shall be determined by taking into account formation fracture gradients and hydrostatic pressure to be contained within the well bore. The conductor and surface casing shall be new pipe or reconditioned pipe that has been tested and inspected to verify a new condition.

(1) Conductor Casing. This casing shall be set in accordance with the table below. A quantity of cement sufficient to fill the annular space back to the Gulf floor must be used. The cement may be washed out or displaced to a depth of 40 feet below the Gulf floor to facilitate casing removal upon well abandonment.

(2) Surface Casing. This casing shall be set at a depth in accordance with the table below and cemented in a manner necessary to protect all fresh water sands and provide well control until the next string of casing is set. This casing shall be cemented with a quantity sufficient to fill the calculated annular space to (a) at least 1,500 feet above the casing shoe, or (b) within 200 feet below the conductor casing. Whenever there are any indications of improper cementing, such as lost returns, cement channeling, or mechanical failure of equipment, a temperature or cement bond survey shall be run, either before or after remedial cementing, to aid in determining whether the casing is properly cemented. If the annular space is not adequately cemented by the primary operation, the operator shall either recement or squeeze cement the shoe after drilling out.

(3) Conductor and Surface Casing Setting Depths. These strings of casing shall be set at the depths specified in the following table subject to minor variation to permit the

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casing to be set in a competent bed; provided, however, that the conductor casing shall be set before drilling into shallow formations known to contain oil or gas or, if unknown, upon encountering such formations. These casing strings shall be run and cemented prior to drilling below the specified setting depths. For those wells which may encounter abnormal pressure conditions, the district engineer may prescribe the exact setting depth within the ranges specified below.

Required Setting Depth Below Gulf Floor (TVD in feet)

Proposed Total Depth of Well or Depth of First Full String of Intermediate Casing (TVD in eet from Rorary Table)	Surface Casing		Conductor Casing	
	Minimum	Maximum	Minimum	Maximum
0 - 7,000	1,500	2,500	300	800
7,000 - 9,000	1,750	3,000	400	800
9,000 -11,000	2,250	3,500	500	900
11,000 -13,000	3,000	4,000	600	900
13,000 -Below	3,500	4,500	700	1,000

C. Intermediate Casing. This string of casing shall be set when required by anticipated abnormal pressure, mud weights, sediment and other well conditions. The intermediate casing shall be new pipe or reconditioned pipe that has been tested and inspected to verify a new condition. A quantity of cement sufficient to cover and isolate all hydrocarbon zones and to isolate abnormal pressure intervals from normal pressure intervals shall be used. If a liner is used as an intermediate string, the cement shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and next larger string has been achieved. The test shall be recorded on the driller's log. When such liner is used as production casing, it shall be extended to the surface and cemented to avoid surface casing being used as production casing.

D. Production Casing. This string of casing shall be set before completing the well for production. The production casing shall be new pipe or reconditioned pipe that has been tested and inspected to verify a new condition. It shall be cemented in a manner necessary to cover or isolate all zones which contain hydrocarbons, but in any case, a calculated volume sufficient to fill the annular space at least 500 feet above the uppermost producible hydrocarbon zone must be used. When a liner is used as production casing, the testing of the seal between the liner top and next larger string shall be conducted as in the case of intermediate liners.

. Pressure Testing. Prior to drilling the plug after cementing, all casing strings, except the drive or structural casing, shall be pressure tested as shown in the table below. This test shall not exceed the working pressure of the casing. The surface casing shall be tested with water in the top 100 feet of the casing. If the pressure declines more than 10% in 30 minutes, or if there is other indication of a leak, the casing shall be recemented, repaired, or an additional casing string run, and the casing shall be tested again in the same manner.

Casing String	Minimum Pressure Test (psi)
Conductor	200
Surface	1,000
Intermediate	1,500 or 0.2 psi/ft., whichever is greater
Liner	1,500 or 0.2 psi/ft., whichever is greater
Production	1,500 or 0.2 psi/ft., whichever is greater

After cementing any of the above strings, drilling shall not be commenced until a time lapse of:

(1) 24 hours, or

(2) 8 hours under pressure for conductor casing string. 12 hours under pressure for all other strings. (Cement is considered under pressure if one or more float valves are employed and are shown to be holding the cement in place or when other means of holding pressure is used.)

All casing pressure tests shall be recorded on the driller's log.

2. Blowout Prevention Equipment. Blowout preventers and related well control equipment shall be installed, used, and tested in a manner necessary to prevent blowouts. Prior to drilling below the conductor casing, blowout prevention equipment shall be installed and maintained ready for use until drilling operations are completed, as follows:

   A. Conductor Casing. Before drilling below this string, at least one remotely controlled bag-type blowout preventer and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed. To avoid formation fracturing from complete shut-in of the well, a large diameter pipe with control valves shall be installed on the conductor casing below the blowout preventer so as to permit the diversion of hydrocarbons and other fluids; except that when the blowout preventer assembly is on the Gulf floor, the choke and kill lines shall be equipped to permit the diversion of hydrocarbons and other fluids.

B. Surface Casing. Before drilling below this string the blowout prevention equipment shall include a minimum of: (1) three remotely controlled, hydraulically operated, blowout preventers with a working pressure which exceeds the maximum anticipated surface pressure, including one equipped with pipe rams, one with blind rams, and one bag-type; (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke manifold; (4) a kill line; and (5) a fill-up line.

C. Intermediate Casing. Before drilling below this string the blowout prevention equipment shall include a minimum of: (1) four remotely controlled, hydraulically operated, blowout preventers with a working pressure which exceeds the maximum anticipated surface pressure, including at least one equipped with pipe rams, one with blind rams, and one bag-type; (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke manifold; (4) a kill line; and (5) a fill-up line.

D. Testing. Ram-type blowout preventers and related control equipment shall be tested with water to the rated working pressure of the stack assembly or to the working pressure of the casing, whichever is the lesser, (1) when installed; (2) before drilling out after each string of casing is set; (3) not less than once each week while drilling; and (4) following repairs that require disconnecting a pressure seal in the assembly. The bag-type blowout preventer shall be tested to 70 percent of the above pressure requirements.

While drill pipe is in use ram-type blowout preventers shall be actuated to test proper functioning once each trip, but in no event less than once each day. The bag-type blowout preventer shall be actuated on the drill pipe once each week. Accumulators or accumulators and pumps shall maintain a pressure capacity reserve at all times to provide for repeated operation of hydraulic preventers. A blowout prevention drill shall be conducted weekly for each drilling crew to insure that all equipment is operational and that crews are properly trained to carry out emergency duties. All blowout preventer tests and crew drills shall be recorded in the driller's log.

E. Other Equipment. An inside blowout preventer assembly (back pressure valve) and drill string safety valve in the open position shall be maintained on the rig floor at all times while drilling operations are being conducted. Separate valves shall be maintained on the rig floor to fit all pipe in the drill string. A Kelly cock shall be installed below the swivel, and an essentially full opening Kelly cock shall be installed at the bottom of the Kelly of such design that it can be run through the blowout preventers.

Mud Program - General. The characteristics, use, and testing of drilling mud and the conduct of related drilling procedures shall be such as are necessary to prevent the blowout of any well. Quantities of mud materials sufficient to insure well control shall be maintained readily accessible for use at all times.

A. Mud Control. Before starting out of hole with drill pipe, the mud shall be circulated with the drill pipe just off bottom until the mud is properly conditioned. When coming out of the hole with drill pipe, the annulus shall be filled with mud before the mud level drops below 100 feet, and a mechanical device for measuring the amount of mud required to fill the hole shall be utilized. The volume of mud required to fill the hole shall be watched, and any time there is an indication of swabbing, or influx of formation fluids, the necessary safety device(s) required in subparagraph 2(E) above shall be installed on the drill pipe, the drill pipe shall be run to bottom, and the mud properly conditioned. The mud shall not be circulated and conditioned except on or near bottom, unless well conditions prevent running the pipe to bottom. The mud in the hole shall be circulated or reverse circulated prior to pulling drill stem test tools from the hole.

B. Mud Testing Equipment. Mud testing equipment shall be maintained on the drilling platform at all times, and mud tests shall be performed daily, or more frequently as conditions warrant.

The following mud system monitoring equipment must be installed (with derrick floor indicators) and used throughout the period of drilling after setting and cementing the conductor casing:

(1) *Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include a visual or audio warning device.*

(2) *Mud volume measuring device for accurately determining mud volumes required to fill the hole on trips.*

(3) *Mud return indicator to determine that returns essentially equal the pump discharge rate.*

Robert F Evans

Robert F. Evans
Supervisor

Approved: August 28, 1969

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

PLUGGING AND ABANDONMENT OF WELLS

his Order is established pursuant to the authority prescribed in 30 CFR 50.11 and in accordance with 30 CFR 250.15. The operator shall comply ith the following minimum plugging and abandonment procedures which have eneral application to all wells drilled for oil and gas. Plugging and bandonment operations must not be commenced prior to obtaining approval rom an authorized representative of the Geological Survey. Oral approvals hall be in accordance with 30 CFR 250.13. Any departures from the equirements specified in this Order must be approved pursuant to 0 CFR 250.12(b).

1. Permanent Abandonment.

   A. Isolation in Uncased Hole. In uncased portions of wells, cement plugs shall be spaced to extend 100 feet below the bottom to 100 feet above the top of any oil, gas, and fresh water zones so as to isolate them in the strata in which they are found and to prevent them from escaping into other strata.

   B. Isolation of Open Hole. Where there is open hole (uncased and open into the casing string above) below the casing, a cement plug shall be placed in the deepest casing string by (1) or (2) below, or in the event lost circulation conditions exist or are anticipated, the plug may be placed in accordance with (3) below:

      (1) A cement plug placed by displacement method so as to extend a minimum of 100 feet above and 100 feet below the casing shoe.

      (2) A cement retainer with effective back pressure control set not less than 50 feet, nor more than 100 feet, above the casing shoe with a cement plug calculated to extend at least 100 feet below the casing shoe and 50 feet above the retainer.

      (3) A permanent type bridge plug set within 150 feet above the casing shoe with 50 feet of cement on top of the bridge plug. This plug shall be tested prior to placing subsequent plugs.

C. Plugging or Isolating Perforated Intervals. A cement plug shall be placed opposite all open perforations (perforations not squeezed with cement) extending a minimum of 100 feet above and 100 feet below the perforated interval or down to a casing plug whichever is less. In lieu of the cement plug, a bridge plug set at a maximum of 150 feet above the open perforations with 50 feet of cement on top may be used provided the perforations are isolated from the hole below.

D. Plugging of Casing Stubs. If casing is cut and recovered, a cement plug 200 feet in length shall be placed to extend 100 feet above and 100 feet below the stub. A retainer may be used in setting the required plug.

E. Plugging of Annular Space. No annular space that extends to the Gulf floor shall be left open to drilled hole below. If this condition exists, the annulus shall be plugged with cement.

F. Surface Plug Requirement. A cement plug of a least 150 feet, with the top of the plug 150 feet or less below the Gulf floor, shall be placed in the smallest string of casing which extends to the surface.

G. Testing of Plugs. The setting and location of the first plug below the top 150-foot plug, will be verified by either (1) placing a minimum pipe weight of 15,000 pounds on the plug, or (2) testing with a minimum pump pressure of 1,000 psig with no more than a 10 percent pressure drop during a 15-minute period.

H. Mud. Each of the respective intervals of the hole between the various plugs shall be filled with mud fluid of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling such interval.

I. Clearance of Location. All casing and piling shall be severed and removed to at least 15 feet below the Gulf floor and the location shall be dragged to clear the well site of any obstructions.

2. *Temporary Abandonment*. Any drilling well which is to be temporarily abandoned shall be mudded and cemented as required for permanent abandonment except for requirements F and I of paragraph 1 above. When casing extends above the Gulf floor, a mechanical bridge plug (retrievable or permanent) shall be set in the casing between 15 and 200 feet below the Gulf floor.

Robert F Evans
Robert F. Evans
Supervisor

Approved: August 28, 1969

Russell G. Wayland
Russell G. Wayland
Chief, Conservation Division

OCS Order No. 4
August 28, 19[illegible]

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

SUSPENSIONS AND DETERMINATION OF WELL PRODUCIBILITY

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.12(d)(1). An OCS lease provides for extension beyond its primary term for as long as oil or gas may be produced from the lease in paying quantities. An OCS lease may be maintained beyond the primary term, in the absence of actual production, when a suspension of operations or production, or both, has been approved. An application for suspension of production for an initial period should be submitted prior to the expiration of the term of a lease. The supervisor may approve a suspension of production provided at least one well has been drilled on the lease and determined to be capable of being produced in paying quantities. The temporary or permanent abandonment of a well will not preclude approval of a suspension of production as provided in 30 CFR 250.12(d)(1). Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

A well may be determined to be capable of producing in paying quantities when the requirements of either 1 or 2 below have been met.

1. Production Tests.

    A. Oil Wells. A production test of at least two hours duration, following stabilization, is required.

    B. Gas Wells. A deliverability test of at least two hours duration, following stabilization, or a four-point back-pressure test, is required.

    C. Witnessing and Results. All tests must be witnessed by an authorized representative of the Geological Survey. Test data accompanied by operator's affidavit, or third-party test data, may be accepted in lieu of a witnessed test provided prior approval is obtained from the appropriate district office. The results of the witnessed or accepted test must justify a determination that the well is capable of producing in paying quantities.

2. Production Capability. Information for determining producibility should be submitted in time to permit one week for evaluation and determination. In cases of urgency, determinations may be conveyed orally. The following may be considered as acceptable evidence that a well is capable of producing in paying quantities:

   A. An induction-electric log of the well, clearly showing a minimum of 15 feet of producible sand in one section which does not include any interval which appears to be water saturated. All of the section counted as producible must exhibit the following properties:

      (1) Electrical spontaneous potential exceeding 20 negative millivolts beyond the shale base line. If mud conditions prevent a 20 negative millivolt reading beyond the shale base line, a gamma ray log deflection of at least 70 percent of the maximum gamma ray deflection in the nearest clean water bearing sand may be substituted.

      (2) A minimum true resistivity ratio of the producible section to the nearest clean water sand of at least 5:1, provided the producible section exhibits a minimum resistivity of 2.0 ohm-meters.

      (3) A porosity log indicating porosity in the producible section.

   B. Sidewall cores and core analysis which indicates that the section is producible.

   C. A wire line formation test or evidence that an attempt was made to obtain such test. The test results must indicate that the section is producible.

   D. All logs run must support other evidence that the section is producible.

Robert F Evans
Robert F. Evans
Supervisor

Approved: August 28, 1969 ✓
Russell G. Wayland
Russell G. Wayland
Chief, Conservation Division

OCS Order No. 5
June 5, 1972

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

INSTALLATION OF SUBSURFACE SAFETY DEVICE

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.41(b). Section 250.41(b) provides as follows:

> (b) Completed Wells. In the conduct of all its operations, the lessee shall take all steps necessary to prevent blowouts, and the lessee shall immediately take whatever action is required to bring under control any well over which control has been lost. The lessee shall: (1) in wells capable of flowing oil or gas, when required by the supervisor, install and maintain in operating condition storm chokes or similar subsurface safety devices; (2) for producing wells not capable of flowing oil or gas, install and maintain surface safety valves with automatic shutdown controls; and (3) periodically test or inspect such devices or equipment as prescribed by the supervisor.

The operator shall comply with the following requirements. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b). All applications for approval under the provisions of this Order shall be submitted to the appropriate District office. References in this Order to approvals, determinations, or requirements are to those given or made by the Supervisor or his delegated representative.

1. Installation. All new and existing tubing installations open to hydrocarbon-bearing zones shall be equipped with a subsurface-controlled or a surface- or other remotely controlled subsurface safety device, to be installed at a depth of 100 feet or more below the sea floor unless, after application and justification, the well is determined to be incapable of flowing oil or gas. These installations shall be made as required in subparagraphs A and B below within two (2) days after stabilized production is established, and during this period of time the well shall not be left unattended while open to production.

A. New Wells. All tubing installations in wells completed after December 1, 1972, shall be equipped with a surface- or other remotely controlled subsurface safety device; provided, that wells with a shut-in tubing pressure of 4,000 psig or greater shall be equipped with a subsurface-controlled subsurface safety device in lieu of a surface- or other remotely controlled subsurface safety device unless a surface- or other remotely controlled subsurface safety device is approved or required. When the shut-in tubing pressure declines below 4,000 psig, a surface- or other remotely controlled subsurface safety device shall be installed when the tubing is first removed and reinstalled.

B. Existing Wells. All tubing installations in wells existing on the date of this Order shall be equipped with a surface- or other remotely controlled subsurface safety device when the tubing is first removed and reinstalled after December 1, 1972; provided, that wells with a shut-in tubing pressure of 4,000 psig or greater shall be equipped with a subsurface-controlled subsurface safety device in lieu of a surface- or other remotely controlled subsurface safety device unless a surface- or other remotely controlled subsurface safety device is approved or required. When the shut-in tubing pressure declines below 4,000 psig, a surface- or other remotely controlled subsurface safety device shall be installed when the tubing is first removed and reinstalled.

Tubing installations in existing wells completed from single-well and multi-well satellite caissons or jackets and sea-floor completions may be equipped with a subsurface-controlled subsurface safety device, in lieu of a surface- or other remotely controlled subsurface safety device, upon application, justification, and approval.

C. Shut-in Wells. A tubing plug shall be installed in lieu of, or in addition to, other subsurface safety devices if a well has been shut in for a period of six (6) months. Such plugs shall be set at a depth of 100 feet or more below the sea floor. All retrievable plugs installed after the date of this Order shall be of the pump-through type. All wells perforated and completed, but not placed on production, shall be equipped with a subsurface safety device or tubing plug within two (2) days after completion.

D. Injection Wells. Subsurface safety devices as required in subparagraphs A and B above shall be installed in all injection wells unless, after application and justification, it is determined that the well is incapable of flowing oil or gas, which condition shall be verified annually.

2. *Technological Advancement.* As technological research, progress, and product improvement result in increased effectiveness of existing safety devices or the development of new devices or systems, such devices or systems may be required or used upon application, justification, and approval. Applications for routine use shall include evidence that the device or system has been field-tested at least once each month for a minimum of six (6) consecutive months, and that each test indicated proper operation.

3. *Testing and Inspection.* Subsurface safety devices shall be designed, adjusted, installed, and maintained to insure reliable operation. During testing and inspection procedures, the well shall not be left unattended while open to production unless a properly operating subsurface safety device has been installed in the well.

    A. *Surface-Controlled Subsurface Safety Devices.* Each surface- or other remotely controlled subsurface safety device installed in a well shall be tested in place for proper operation when installed and thereafter at intervals not exceeding six (6) months. If the device does not operate properly, it shall be removed, repaired, and reinstalled or replaced and tested to insure proper operation.

    B. *Subsurface-Controlled Subsurface Safety Devices.* Each subsurface-controlled subsurface safety device installed in a well shall be removed, inspected, and repaired or adjusted as necessary and reinstalled at intervals not exceeding six (6) months; provided, that such removable devices set in a landing nipple shall be removed, inspected, and repaired or adjusted as necessary and reinstalled at intervals not exceeding twelve (12) months. Each velocity-type device shall be designed to close at a flow rate not to exceed the larger of either 150 percent of, or 200 BFPD above, the most recent well-test rate which equals or exceeds the approved production rate. The above closing flow rate shall not exceed the calculated capacity of the well to produce against a flowing wellhead pressure of 50 psig. Each preset tubing-pressure-actuated device shall be designed to close prior to reduction of the flowing wellhead pressure to 50 psig.

    C. *Tubing Plugs.* A shut-in well equipped with a tubing plug shall be inspected for leakage by opening the well to possible flow at intervals not exceeding six (6) months. If sustained liquid flow exceeds 400 cc/min., or gas flow exceeds 15 cu. ft./min., the plug shall be removed, repaired, and reinstalled or an additional tubing plug installed to prevent leakage.

4. *Temporary Removal.* Each wireline- or pumpdown-retrievable subsurface safety device may be removed, without further authority or notice, for a routine operation which does not require approval of a Sundry Notice and Report on Wells (Form 9-331) for a period not to exceed fifteen (15) days. The well shall be clearly identified as being without a subsurface safety device and shall not be left unattended while open to production. The provisions of this paragraph are not applicable to the testing and inspection procedures in paragraph 3 above.

5. *Additional Protective Equipment.* All tubing installations made after the date of this Order in which a wireline- or pumpdown-retrievable subsurface safety device is to be installed shall be equipped with a landing nipple, with flow couplings or other protective equipment above and below, to provide for setting of the subsurface safety device. All wells in which a subsurface safety device or tubing plug is installed shall have the tubing-casing annulus packed off above the uppermost open casing perforations. The control system for all surface-controlled subsurface safety devices shall be an integral part of the platform shut-in system, or of an independent remote shut-in system.

6. *Departures.* All departures (or waivers) approved prior to the date of this Order are hereby terminated as of December 1, 1972, unless new applications are submitted prior to that date. All such new applications will be considered for approval pursuant to 30 CFR 250.12(b) and the requirements of this Order. All applications for departures shall include a detailed statement of the well conditions, efforts made to overcome any difficulties, and proposed alternate safety measures.

7. *Emergency Action.* All tubing installations open to hydrocarbon-bearing zones and not equipped with a subsurface safety device as permitted by this Order shall be clearly identified as not being so equipped, and a subsurface safety device or tubing plug shall be available at the field location. In the event of an emergency, such as an impending hurricane, such device or plug shall be promptly installed within the limits of practicability, due consideration being given to personnel safety.

8. *Records.* The operator shall maintain the following records for a minimum period of one year for each subsurface safety device and tubing plug installed, which records shall be available to any authorized representative of the Geological Survey.

   A. *Field Records.* Individual well records shall be maintained at or near the field and shall include, as a minimum, the following information:

(1) *A record which will give design and other information; i.e., make, model, type, spacers, bean and spring size, pressure, etc.*

(2) *Verification of assembly by a qualified person in charge of installing the device and installation date.*

(3) *Verification of setting depth and all operational tests as required in this Order.*

(4) *Removal date, reason for removal, and reinstallation date.*

(5) *A record of all modifications of design in the field.*

(6) *All mechanical failures or malfunctions, including sand-cutting, of such devices, with notation as to cause or probable cause.*

(7) *Verification that a failure report was submitted.*

B. *Other Records. The following records, as a minimum, shall be maintained at the operator's office:*

(1) *Verified design information of subsurface-controlled subsurface safety devices for the individual well.*

(2) *Verification of assembly and installation according to design information.*

(3) *All failure reports.*

(4) *All laboratory analysis reports of failed or damaged parts.*

(5) *Quarterly failure-analysis report.*

9. *Reports. Well completion reports (Form 9-330) and any subsequent reports of workover (Form 9-331) shall include the type and the depth of the subsurface safety devices and tubing plugs installed in the well or indicate that a departure has been granted.*

To establish a failure-reporting and corrective-action program as a basis for reliability and quality control, each operator shall submit a quarterly failure-analysis report to the office of the Supervisor, identifying mechanical failures by lease and well, make and model, cause or probable cause of failure, and action taken to correct the failure. The reporting period shall begin the first day of the month following the date of this

Order. The reports shall be submitted by February 28, May 31, August 31, and November 30 for the periods ending January 31, April 30, July 31, and October 31 of each year.

Robert F Evans
Robert F. Evans
Supervisor

Approved: June 5, 1972 ✓

Russell G. Wayland
Russell G. Wayland
Chief, Conservation Division

OCS Order No. 6
August 28, 1969

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

PROCEDURE FOR COMPLETION OF OIL AND GAS WELLS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.92. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Wellhead Equipment and Testing Procedures.

   A. Wellhead Equipment. All completed wells shall be equipped with casingheads, wellhead fittings, valves and connections with a rated working pressure equal to or greater than the surface shut-in pressure of the well. Connections and valves shall be designed and installed to permit fluid to be pumped between any two strings of casing. Two master valves shall be installed on the tubing in wells with a surface pressure in excess of five thousand pounds per square inch. All wellhead connections shall be assembled and tested, prior to installation, by a fluid pressure which shall be equal to the rated test pressure of the fitting to be installed.

   B. Testing Procedure. Any wells showing sustained pressure on the casinghead, or leaking gas or oil between the production casing and the next larger casing string, shall be tested in the following manner: The well shall be killed with water or mud and pump pressure applied. Should the pressure at the casinghead reflect the applied pressure, the casing shall be condemned. After corrective measures have been taken, the casing shall be tested in the same manner. This testing procedure shall be used when the origin of the pressure cannot be determined otherwise.

2. Storm Choke. All completed wells shall meet the requirements prescribed in OCS Order No. 5.

3. Procedures for Multiple or Tubingless Completions.

A. Multiple Completions.

(1) Information shall be submitted on, or attached to, Form 9-331 showing top and bottom of all zones proposed for completion or alternate completion, including a partial electric log and a diagrammatic sketch showing such zones and equipment to be used.

(2) When zones approved for multiple completion become intercommunicated the lessee shall immediately repair and separate the zones after approval is obtained.

B. Tubingless Completions.

(1) All tubing strings in a multiple completed well shall be run to the same depth below the deepest producible zone.

(2) The tubing string(s) shall be new pipe and cemented with a sufficient volume to extend a minimum of 500 feet above the uppermost producible zone.

(3) A temperature or cement bond log shall be run in all tubingless completion wells where lost circulation or other unusual circumstances occur during the cementing operations.

(4) Information shall be submitted on, or attached to, Form 9-331 showing the top and bottom of all zones proposed for completion or alternate completion, including a partial electric log and a diagrammatic sketch showing such zones and equipment to be used.

Robert F. Evans
Robert F. Evans
Supervisor

Approved: August 28, 1969 ✓

Russell G. Wayland
Russell G. Wayland
Chief, Conservation Division

(c) The lessee's liability to third parties, other than for cleaning up the pollutant in accordance with subsection (b) above, shall be governed by applicable law.

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Pollution Prevention. In the conduct of all oil, gas and sulphur operations, the operator shall prevent pollution of the waters of the Gulf of Mexico. The operator shall comply with the following pollution prevention requirements:

   A. Liquid Disposal.

   (1) Oil in any form shall not be disposed of into the waters of the Gulf.

   (2) Liquid waste materials containing substances which may be harmful to aquatic life or wildlife, or injurious in any manner to life or property, shall be treated to avoid disposal of harmful substances into the waters of the Gulf.

   (3) Drilling mud containing oil shall not be disposed of into the Gulf. Drilling mud containing toxic substances shall be neutralized prior to disposal.

   B. Solid Waste Disposal.

   (1) Drill cuttings, sand, and other solids containing oil shall not be disposed of into the Gulf unless the oil has been removed.

   (2) Mud containers and other solid waste materials shall be incincerated or transported to shore for disposal.

   C. Production Facilities.

   (1) All production facilities, such as separators, tanks, treaters, and other equipment, shall be such as are necessary to control the maximum anticipated pressures and production of oil, gas, and sulphur, and shall be maintained at all times in a manner necessary to prevent pollution.

(2) All platforms and structures shall be curbed and connected by drains to a collecting tank or sump unless drip pans, or equivalents, are placed under equipment, from which a pollutant may spill into the Gulf, and piped to a tank or sump.

(3) The operator's personnel shall be thoroughly instructed in the techniques of equipment maintenance and operation for the prevention of pollution. Non-operator personnel shall be informed in writing, prior to executing contracts, of the operator's obligations to prevent pollution.

2. Inspections and Reports. The operator shall comply with the following pollution inspection and reporting requirements:

A. Pollution Inspections.

(1) Manned facilities shall be inspected daily.

(2) Unattended facilities, including those equipped with remote control and monitoring systems, shall be inspected at frequent intervals. The district engineer may prescribe the frequency of inspections for these facilities.

B. Pollution Reports.

(1) All spills or leakage of oil and liquid pollutants shall be recorded showing the cause, size of spill, and action taken, and the record shall be maintained and available for inspection by the supervisor. All spills or leakage of less than 15 barrels shall be reported to the district engineer when requested by him.

(2) All spills or leakage of oil and liquid pollutants of 15 to 50 barrels shall be reported orally to the district engineer without delay and shall be confirmed in writing.

(3) All spills or leakage of oil and liquid pollutants of a substantial size or quantity, which is defined as more than 50 barrels, and those of any size or quantity which cannot be immediately controlled, shall be reported orally without delay to the supervisor, the district engineer, the Coast Guard, and the Regional Director, Federal Water Pollution Control Administration. All oral reports shall be confirmed in writing.

(4) *Operators shall notify each other upon observation of equipment malfunction or pollution resulting from another's operation.*

3. *Control and Removal.*

A. *Corrective Action. Immediate corrective action shall be taken in all cases where pollution has occurred. Each operator shall have an emergency plan for initiating corrective action to control and remove pollution and such plan shall be filed with the supervisor. Corrective action taken under the plan shall be subject to modification when directed by the supervisor.*

B. *Equipment. Standby pollution control equipment shall be maintained by or shall be immediately available to each operator at a land base location. This equipment shall include containment booms, skimming apparatus, and approved chemical dispersants and shall be available prior to the commencement of operations. The equipment shall be regularly inspected and maintained in good condition for use. The equipment and the location of land bases shall be approved by the supervisor. The operator shall notify the supervisor of the location at which such equipment is located for operations conducted on or for each lease. All changes in location and equipment maintained at each location shall be approved by the supervisor.*

Robert F. Evans
Supervisor

Approved: August 28, 1969

Russell G. Wayland
Russell G. Wayland
Chief, Conservation Division

OCS Order No. 8
October 30, 1970

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

APPROVAL PROCEDURE FOR INSTALLATION AND OPERATION OF PLATFORMS, FIXED AND MOBILE STRUCTURES, AND ARTIFICIAL ISLANDS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.19(a). Section 250.19(a) provides as follows:

> (a) The Supervisor is authorized to approve the design, other features, and plan of installation of all platforms, fixed structures, and artificial islands as a condition of the granting of a right of use or easement under Paragraphs (a) and (b) of Section 250.18 or authorized under any lease issued or maintained under the Act.

he operator shall be responsible for compliance with the requirements of his Order in the installation and operation of all platforms, fixed and obile structures, and artificial islands, including all facilities nstalled on a platform or structure whether or not operated or owned by he operator. Any departures from the requirements specified in this rder must be approved pursuant to 30 CFR 250.12(1).

1. The following requirements are applicable to all platforms approved and installed subsequent to the effective date of this Order, and to all platforms when structural and equipment modifications are to be made:

    A. General Design. The design of platforms, fixed structures, and artificial islands shall include consideration of such factors as water depth, surface and subsurface soil conditions, wave and current forces, wind forces, total equipment weight, and other pertinent geological, geographical, environmental, and operational conditions.

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B. Application. The operator shall submit, in duplicate, the following to the appropriate District Office for approval:

(1) Design Features. Information relative to design features on an 8" x 10½" plat or plats showing the platform dimensions, plan and two elevations, number and location of well slots, and water depth. In addition, the plat shall include:

(a) Nominal size and thickness range of piling.

(b) Nominal size and thickness range of jacket column leg.

(c) Nominal size and thickness range of deck column leg.

(d) Design piling penetration.

(e) Maximum bearing and lateral load per pile in tons.

(f) Identification data which shall be the lease number, block number, area, and operator.

(g) The following certification signed and dated with the title of the company representative:

> "___Operator___ certifies that this platform has been certified by a registered professional engineer and that the structure will be constructed, operated, and maintained as described in the application, and any approved modification thereto. Certified plans are on file at ____________________."

(2) Non-design Features. Information relative to non-design features including the following:

(a) Primary use intended, including drilling, production of oil and gas, sulphur, or salt.

(b) Personnel and personnel transfer facilities including living quarters, boat landings, and heliport.

(c) Type of deck, such as steel or wood, and whether coated with protective material.

(d) Method of protection from corrosion.

(e) Production facilities including separators, treaters, storage tanks, compressors, line pumps, and metering devices, except that when initially designed and utilized for drilling, this information may be submitted prior to installation.

(f) Safety and pollution control equipment and features.

(g) Other information when required.

C. Certified Plan. Detailed structural plans certified by a registered professional engineer shall be on file and maintained by the operator or his designee.

2. Safety and Pollution Control Equipment and Procedures.

A. The following requirements shall apply to all platforms. Operators of platforms installed prior to the effective date of this Order shall comply with the requirements of subparagraphs (1)(a) through (f), (2), and (3) within three months, with subparagraphs (1)(g) and (4) within six months, and with subparagraphs (5), (6), (7), (8), and (9) within one year, from the effective date of this Order.

(1) The following shut-in devices shall be installed and maintained in an operating condition on all pressurized vessels and water separation facilities when such vessels and separation facilities are in service. The operator shall submit records to the appropriate District Office semi-annually showing the present status and past history of each device including dates and details of inspection, testing, repairing, adjustment, and reinstallation.

(a) All separators shall be equipped with high-low pressure shut-in sensors, low level shut-in controls, and a relief valve. High liquid level control devices shall be installed when the vessel can discharge to a flare.

(b) All pressure surge tanks shall be equipped with a high and low pressure shut-in sensor, a high level shut-in control, flare line, and relief valve.

(c) Atmospheric surge tanks shall be equipped with a high level shut-in sensor.

(d) All other hydrocarbon handling pressure vessels shall be equipped with high-low pressure shut-in sensors, high-low level shut-in controls, and relief valves, unless determined to be otherwise protected.

(e) Pilot-operated pressure relief valves shall be equipped to permit testing with an external pressure source. Spring-loaded pressure relief valves shall either be bench-tested or equipped to permit testing with an external pressure source. A relief valve shall be set no higher than the designed working pressure of the vessel. The high pressure shut-in sensor shall be set no higher than 5% below the rated or designed working pressure and the low pressure shut-in sensor shall be set no lower than 10% below the lowest pressure in the operating pressure range on all vessels with a rated or designed working pressure of more than 400 psi. On lower pressure vessels the above percentages shall be used as guidelines for sensor settings considering pressure and operating conditions involved; except that sensor settings shall not be within 5 psi of the rated or designed working pressure or the lowest pressure in the operating pressure range.

(f) All sensors shall be equipped to permit testing with an external pressure source.

(g) All flare lines shall be equipped with a scrubber or similar separation equipment.

(2) The following remote and local automatic shut-in devices shall be installed and maintained in an operating condition at all times when the affected well (or wells) is producing. The operator shall submit records to the appropriate District Office semi-annually showing the present status and past history of each such device including dates and details of inspection, testing, repairing, adjustment, and reinstallation.

(a) All wellhead assemblies shall be equipped with an automatic fail-close valve. Automatic safety valves temporarily out of service shall be flagged.

(b) All flowlines from wellheads shall be equipped with high-low pressure sensors located close to the wellhead. The pressure sensors shall be set to activate the wellhead valve in the event of abnormal pressures in the flowline.

(c) All headers shall be equipped with check valves on the individual flowlines. The flowline and valves from each well located upstream of, and including, the header valves shall withstand the shut-in pressure of that well, unless protected by a relief valve with connections to bypass the header. If there is an inlet valve to a separator, the valve, flowline, and all equipment upstream of the valve shall also withstand shut-in wellhead pressure, unless protected by a relief valve with connections to bypass the header.

(d) All pneumatic shut-in control lines shall be equipped with fusible material at strategic points.

(e) Remote shut-in controls shall be located on the helicopter deck and all exit stairway landings, including at least one on each boat landing. These controls shall be quick-opening valves.

(f) All pressure sensors shall be tested for proper pressure settings monthly for at least four months. At such time as the monthly results are consistent, a quarterly test shall be required for at least one year. If these results are consistent, a longer period of time between testing may then be approved by the Supervisor. In the event any testing sequence reveals inconsistent results, the monthly testing sequence shall be reinstituted. Results of all tests shall be recorded and maintained in the field.

(g) All automatic wellhead safety valves shall be tested for operation weekly. All automatic wellhead safety valves shall be tested for holding pressure monthly. If these results are consistent, a longer period of time between pressure tests, not to exceed quarterly, may then be approved by the Supervisor. In the event that any pressure testing sequence, exceeding monthly, reveals inconsistent results, the monthly testing sequence shall be reinstituted. Results of all tests shall be recorded and maintained in the field.

(h) Check valves shall be tested for holding pressure monthly for at least four months. At such time as the monthly results are satisfactory, a quarterly test shall be required for at least one year. If these results are consistent, a longer period of time between testing may then be approved by the Supervisor. In the event any testing sequence reveals inconsistent results, the monthly testing sequence shall be reinstituted. Results of all tests shall be recorded and maintained in the field.

(i) A complete testing and inspection of the safety system shall be witnessed by Geological Survey representatives at the time production is commenced. Thereafter, the operator shall arrange for a test every six months. The test shall be conducted when it can be witnessed by Geological Survey representatives.

(j) A standard procedure for testing of safety equipment shall be prepared and posted in a prominent place on the platform.

(3) Curbs, gutters, and drains shall be constructed in all deck areas in a manner necessary to collect all contaminants, unless drip pans or equivalent are placed under equipment and piped to a sump which will automatically maintain the oil at a level sufficient to prevent discharge of oil into the Gulf waters. Alternate methods to obtain the same results will be acceptable. These systems shall not permit spilled oil to flow into the wellhead area.

(4) An auxiliary electrical power supply shall be installed to provide emergency power capable of operating all electrical equipment required to maintain safety of operation in the event the primary electrical power supply fails.

(5) The following requirements shall apply to the handling and disposal of all produced waste water discharged into the Gulf of Mexico. The disposal of waste water other than into the Gulf waters shall have the method and location approved by the Supervisor.

(a) Water discharged shall not create conditions which will adversely affect the public health or the use of the waters for the propagation of aquatic life, recreation, navigation, or other legitimate uses.

(b) Waste water disposal systems shall be designed and maintained to reduce the oil content of the disposed water to an average of not more than fifty ppm. An effluent sampling station shall be located at a point prior to discharge into the receiving waters where a representative sample of the treated effluent can be obtained. On one day each month four effluent samples shall be taken within a 24-hour period and determinations shall be made on the temperature, suspended solids, settleable solids, pH, total oil content, and volume of sample obtained.

All samples shall be taken and all analyses for oil content shall be performed in accordance with the American Society for Testing and Materials test D1340, "Oily Matter in Industrial Waste Water". The Supervisor may approve different methods for determination of oil content if the method to be used is indicated to be reliable. No effluent containing in excess of one hundred ppm of total oil content shall be discharged into the Gulf of Mexico. A written report of the results shall be furnished to the Regional Office annually. The report shall contain dates, time and location of sample, volumes of waste discharge on the date of sampling in barrels per day, and the results of the specific analysis and physical observations.

(6) A firefighting system shall be installed and maintained in an operating condition in accordance with the following:

(a) A fixed automatic water spray system shall be installed in all inadequately ventilated wellhead areas as these areas are defined in Paragraph 9 API RP 500A. These systems shall be installed in accordance with the most current edition of National Fire Protection Association's Pamphlet No. 15.

(b) A firewater system of rigid pipe with fire hose stations shall be installed and may include a fixed water spray system. Such a system shall be installed in a manner necessary to provide needed protection in areas where production handling equipment is located. A firefighting system using chemicals may be considered for installation in certain platform areas in lieu of a firewater system in that area, if determined to provide equivalent fire protection control.

(c) Pumps for the firewater systems shall be inspected and test-operated weekly. A record of the tests shall be maintained in the field and submitted semi-annually to the appropriate District Office. An alternate fuel or power source shall be installed to provide continued pump operation during platform shutdown unless an alternate firefighting system is provided.

(d) Portable fire extinguishers shall be located in the living quarters and in other strategic areas.

(e) A diagram of the firefighting system showing the location of all equipment shall be posted in a prominent place on the platform and a copy submitted to the appropriate District Office.

(7) An automatic gas detector and alarm system shall be installed and maintained in an operating condition in accordance with the following:

(a) Gas detection systems shall be installed in all enclosed areas containing gas handling facilities or equipment and in other enclosed areas which are classified as hazardous areas as defined in API RP 500 and the most current edition of the National Electric Code.

(b) All gas detection systems shall be capable of continuously monitoring for the presence of combustible gas in the areas in which the detection devices are located.

(c) The central control shall be capable of giving an alarm at some point below the lower explosive limit of 1.3% as shown in the Bureau of Mines Bulletin No. 503. This low level shall be for alarm purposes only.

(d) A high level setting of not more than 4.9% shall be used for shut-in sequences and the operation of emergency equipment.

(e) An application for the installation and maintenance of any gas detection system shall be filed with the appropriate District Office for approval. The application shall include the following:

(i) Type, location, and number of detection or sampling heads.

(ii) Cycling, noncycling, and frequency information.

(iii) Type and kind of alarm including emergency equipment to be activated.

(iv) Method used for detection of combustible gas.

(v) Method and frequency of calibration.

(vi) A diagram of the gas detection system.

(vii) Other pertinent information.

(f) A diagram of the gas detection system showing the location of all gas detection points shall be posted in a prominent place on the platform.

(8) The following requirements shall be applicable to all electrical equipment and systems installed:

(a) All engines shall be equipped with low-tension ignition systems containing rigid connections and shielded wiring which shall prevent the release of sufficient electrical energy under normal or abnormal conditions to cause ignition of a combustible mixture.

(b) All electrical generators, motors, and lighting systems shall be installed, protected, and maintained in accordance with the most current edition of the National Electric Code and API RP 500A and B, as appropriate.

(c) Marine-armored cable or metal-clad cable may be substituted for wire in conduit in any area.

(9) Sewage disposal systems shall be installed and used in all cases where sewage is discharged into the Gulf of Mexico. Sewage is defined as human body wastes and the wastes from toilets and other receptacles intended to receive or retain body wastes. Following sewage treatment, the effluent shall contain 50 ppm or less of biochemical oxygen demand (BOD), 150 ppm or less of suspended solids, and shall have a minimum chlorine residual of 1.0 mg/liter after a minimum retention time of fifteen minutes.

B. The requirements of subparagraphs 2.A(3), (4), (8), and (9) shall apply to all mobile drilling structures used to conduct drilling or workover operations on Federal leases in the Gulf of Mexico.

Robert F Evans

Robert F. Evans
Supervisor

Approved: October 30, 1970

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

APPROVAL PROCEDURE FOR OIL AND GAS PIPELINES

is Order is established pursuant to the authority prescribed in 30 CFR .11 and in accordance with 30 CFR 250.19(b). Section 250.19(b) vides as follows:

> (b) The Supervisor is authorized to approve the design, other features, and plan of installation of all pipelines for which a right of use or easement has been granted under Paragraph (c) of Section 250.18 or authorized under any lease issued or maintained under the Act, including those portions of such lines which extend onto or traverse areas other than the Outer Continental Shelf.

operator shall comply with the following requirements. Any departures m the requirements specified in this Order must be approved pursuant to CFR 250.12(b).

1. General Design. All pipelines shall be designed and maintained in accordance with the following:

   A. The operator shall be responsible for the installation of the following control devices on all oil and gas pipelines connected to a platform including pipelines which are not operated or owned by the operator. Operators of platforms installed prior to the effective date of this Order shall comply with the requirements of subparagraphs (1) and (2) within six months of the effective date of this Order. The operator shall submit records semi-annually showing the present status and past history of each device, including dates and details of inspection, testing, repairing, adjustment, and reinstallation.

      (1) All oil and gas pipelines leaving a platform receiving production from the platform shall be equipped with a high-low pressure sensor to directly or indirectly shut-in the wells on the platform.

(2) (a) All oil and gas pipelines delivering production to production facilities on a platform shall be equipped with an automatic shut-in valve connected to the platform's automatic and remote shut-in system.

(b) All oil and gas pipelines coming onto a platform shall be equipped with a check valve to avoid backflow.

(c) Any oil or gas pipelines crossing a platform which do not deliver production to the platform, but which may or may not receive production from the platform, shall be equipped with high-low pressure sensors to activate an automatic shut-in valve to be located in the upstream portion of the pipeline at the platform. This automatic shut-in valve shall be connected to either the platform automatic and remote shut-in system or to an independent remote shut-in system.

(d) All pipeline pumps shall be equipped with high-low pressure shut-in devices.

B. All pipelines shall be protected from loss of metal by corrosion that would endanger the strength and safety of the lines either by providing extra metal for corrosion allowance, or by some means of preventing loss of metal such as protective coatings or cathodic protection.

C. All pipelines shall be installed and maintained to be compatible with trawling operations and other uses.

D. All pipelines shall be hydrostatically tested to 1.25 times the designed working pressure for a minimum of 2 hours prior to placing the line in service.

E. All pipelines shall be maintained in good operating condition at all times and inspected monthly for indication of leakage using aircraft, floating equipment, or other methods. Records of these inspections including the date, methods, and results of each inspection shall be maintained by the pipeline operator and submitted annually by April 1. The pipeline operator shall submit records indicating the cause, effect, and remedial action taken regarding all pipeline leaks within one week following each such occurrence.

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F. All pipelines shall be designed to be protected against water currents, storm scouring, soft bottoms, and other environmental factors.

2. Application. The operator shall submit in duplicate the following to the Supervisor for approval:

   A. Drawing on 8" x 10½" plat or plats showing the major features and other pertinent data including: (1) water depth, (2) route, (3) location, (4) length, (5) connecting facilities, (6) size, and (7) burial depth, if buried.

   B. A schematic drawing showing the following pipeline safety equipment and the manner in which the equipment functions: (1) high-low pressure sensors, (2) automatic shut-in valves, and (3) check valves.

   C. General information concerning the pipeline including the following:

      (1) Product or products to be transported by the pipeline.

      (2) Size, weight, and grade of the pipe.

      (3) Length of line.

      (4) Maximum water depth.

      (5) Type or types of corrosion protection.

      (6) Description of protective coating.

      (7) Bulk specific gravity of line (with the line empty).

      (8) Anticipated gravity or density of the product or products.

      (9) Design working pressure and capacity.

      (10) Maximum working pressure and capacity.

      (11) Hydrostatic pressure and hold time to which the line will be tested after installation.

      (12) Size and location of pumps and prime movers.

      (13) Any other pertinent information as the Supervisor may prescribe.

3. *Completion Report*. The operator shall notify the Supervisor when installation of the pipeline is completed and submit a drawing on 8" x 10½" plats showing the location of the line as installed, accompanied by all hydrostatic test data including procedure, test pressure, hold time, and results.

Robert F Evans
Robert F. Evans
Supervisor

Approved: October 30, 1970 ✓

Russell G. Wayland
Russell G. Wayland
Chief, Conservation Division

OCS Order No. 10
August 28, 1969

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL SULPHUR LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

SULPHUR DRILLING PROCEDURES OFF LOUISIANA AND TEXAS

Order is established pursuant to the authority prescribed in 30 CFR 011 and in accordance with 30 CFR 250.34, 250.41, and 250.91. All oratory core holes for sulphur and all sulphur development wells shall rilled in accordance with the provisions of this Order, except that elopment wells shall be drilled in accordance with field rules when blished by the supervisor. Each Application to Drill (Form 9-331C) l include all information required under 30 CFR 250.91 and the integrated ng, cementing, mud, and blowout prevention program for the well. The ator shall comply with the following requirements. Any departures from requirements specified in this Order must be approved pursuant to FR 250.12(b).

1. Well Casing and Cementing. All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1). Special consideration to casing design shall be given to compensate for effects caused by subsidence, corrosion, and temperature variation. All depths refer to true vertical depth (TVD).

   A. Drive or Structural Casing. This casing shall be set by drilling, driving, or jetting to a minimum depth of 100 feet below the Gulf floor, or to such greater depth required to support unconsolidated deposits and to provide hole stability for initial drilling operations. If drilled in, the drilling fluid shall be a type that will not pollute the Gulf, and a quantity of cement sufficient to fill the annular space back to the Gulf floor must be used.

   B. Conductor Casing. This casing shall be set and cemented before drilling into shallow formations known to contain hydrocarbons or, if unknown, upon encountering such formations. Conductor casing shall extend to a depth of not less than 350 feet nor more than 750 feet below the Gulf floor. A quantity of cement sufficient to fill the annular space back to the Gulf floor must be used. The cement may be washed out or displaced to a depth of 40 feet below the Gulf floor to facilitate casing removal upon well abandonment.

C. Caprock Casing. This casing shall be set at the top of the caprock and be cemented with a quantity of cement sufficient to fill the annular space back to the Gulf floor. Stage cementing or other cementing method shall be used to insure cement returns to the Gulf floor.

2. Blowout Prevention Equipment. Blowout preventers and related well control equipment shall be installed, used, and tested in a manner necessary to prevent blowouts. Prior to drilling below the conductor casing, blowout prevention equipment shall be installed and maintained ready for use until drilling operations are completed, as follows:

A. Conductor Casing. Before drilling below this string, at least one remotely controlled bag-type blowout preventer and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed. To avoid formation fracturing from complete shut-in of the well, a large diameter pipe with control valves shall be installed on the conductor casing below the blowout preventer so as to permit the diversion of hydrocarbons and other fluids; except that when the blowout preventer assembly is on the Gulf floor, the choke and kill lines shall be equipped to permit the diversion of hydrocarbons and other fluids.

B. Caprock Casing. Before drilling below this string, the blowout prevention equipment shall include a minimum of: (1) three remotely controlled, hydraulically operated, blowout preventers with a working pressure which exceeds the maximum anticipated surface pressure, including one equipped with pipe rams, one with blind rams, and one bag-type; (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke manifold; (4) a kill line; and (5) a fill-up line.

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C. *Testing.* Ram-type blowout preventers and related control equipment shall be tested with water to the rated working pressure of the stack assembly, or to the working pressure of the casing, whichever is the lesser, (1) when installed; (2) before drilling out after each string of casing is set; (3) not less than once each week while drilling; and (4) following repairs that require disconnecting a pressure seal in the assembly. The bag-type blowout preventer shall be tested to 70 percent of the above pressure requirements.

While drill pipe is in use ram-type blowout preventers shall be actuated to test proper functioning once each day. The bag-type blowout preventer shall be actuated on the drill pipe once each week. Accumulators or accumulators and pumps shall maintain a pressure capacity reserve at all times to provide for repeated operation of hydraulic preventers. A blowout prevention drill shall be conducted weekly for each drilling crew to insure that all equipment is operational and that crews are properly trained to carry out emergency duties. All blowout preventer tests and crew drills shall be recorded on the driller's log.

D. *Other Equipment.* A drill string safety valve in the open position shall be maintained on the rig floor at all times while drilling operations are being conducted. Separate valves shall be maintained on the rig floor to fit all pipe in the drill string. A Kelly cock shall be installed below the swivel.

3) *Mud Program - General.* The characteristics, use, and testing of drilling mud and the conduct of related drilling procedures shall be such as are necessary to prevent the blowout of any well. Quantities of mud materials sufficient to insure well control shall be maintained readily accessible for use at all times. The following mud control and testing equipment requirements are applicable to operations conducted prior to drilling below the caprock casing.

A. *Mud Control.* Before starting out of the hole with drill pipe, the mud shall be circulated with the drill pipe just off bottom until the mud is properly conditioned. When coming out of the hole with drill pipe, the annulus shall be filled with mud before the mud level drops below 100 feet, and a mechanical device for measuring the amount of mud required to fill the hole shall be utilized. The volume of mud required to fill the hole shall be watched, and any time there is an indication of swabbing, or influx of formation fluids, the drill pipe shall be run to bottom, and the mud properly conditioned. The mud shall not be circulated and conditioned except on or near bottom, unless well conditions prevent running the pipe to bottom.

B. Mud Testing and Equipment. Mud testing equipment shall be maintained on the drilling platform at all times, and mud tests shall be performed daily, or more frequently as conditions warrant.

The following mud system monitoring equipment must be installed (with derrick floor indicators) and used throughout the period of drilling after setting and cementing the conductor casing:

(1) Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include a visual or audio warning device.

(2) Mud volume measuring device for accurately determining mud volumes required to fill the hole on trips.

(3) Mud return indicator to determine that returns essentially equal the pump discharge rate.

Robert F. Evans
Supervisor

Approved: August 28, 1969 ✓

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

OCS Order No. 11
April 5, 1972

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

INTERIM OIL AND GAS PRODUCTION RATES

This Interim Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.16 and supersedes Interim OCS Order No. 11, dated December 11, 1970, and the first and second revisions thereof, dated February 11, 1971, and March 29, 1971, respectively. The provisions of this Interim Order and the maximum production rates heretofore approved under Interim Order No. 11, dated December 11, 1970, will remain in full force and effect until superseded, amended, or terminated. 30 CFR 250.16 provides as follows:

> Well potentials and permissible flow. The supervisor is authorized to specify the time and method for determining the potential capacity of any well and to fix, after appropriate notice, the permissible production of any such well that may be produced when such action is necessary to prevent waste or to conform with such proration rules, schedules, or procedures as may be established by the Secretary.

In accordance with the notice appearing in the Federal Register, dated December 5, 1970 (35 F.R. 18559), the provisions of this Order are applicable to all oil and gas wells located on the Outer Continental Shelf of the Gulf of Mexico off the State of Texas and the undisputed areas off the State of Louisiana; provided, however, this order shall not apply to any wells on oil and gas leases situated landward of the line, or transected by the line, described in paragraph 3 of the Supplemental Decree entered December 20, 1971, in United States v. Louisiana, S. Ct. No. 9, Original (40 L.W. 3287). Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12 (b).

1. *Maximum Production Rates.*

   A. *Producible Wells.* Effective May 1, 1972, all producible oil and gas wells and reservoirs may be produced at daily rates not to exceed the Maximum Efficient Rate (MER), subject to the limitations set forth in paragraph 5 below.

   B. *New Completions and Recompletions.* New oil and gas well completions and recompletions shall be produced at a rate established by the Supervisor. A testing period not to exceed 30 days will be allowed prior to setting the maximum production rate for the well. At the end of the testing period, the operator shall submit a detailed determination of the MER justifying a proposed maximum rate of production for the Supervisor's approval. The initial production test of all completions and recompletions may be witnessed by a representative of the Supervisor.

2. *Definition of MER.* The MER is defined as that rate for each reservoir and each well which, if exceeded, would lead to avoidable underground waste through loss of ultimate recovery of oil and gas from that reservoir. It is dependent on the recovery mechanism operative for the current producing period, and is based on engineering and geological information.

3. *Determination of MER.* On or before May 1, 1972, each operator shall submit reports, for approval by the Supervisor, showing the operator's estimate of the MER for each oil and gas well and reservoir on those leases in the area removed from dispute in *United States v. Louisiana*, S. Ct. No. 9, Original, by entry of the Supplemental Decree of December 20, 1971, in that litigation (40 L.W. 3287). Reports shall be identified by the name of the field, the OCS lease number, the well number, and the designation and depth of the productive zone. As soon as available and prior to July 1, 1972, each operator shall submit the technical information and methods used to determine the MER applicable to each well and reservoir.

   Revisions in the operator's estimate of the MER for oil and gas wells and reservoirs located on leases subject to this Interim Order shall be submitted to the Supervisor for approval.

4. *Reports.* Each operator shall submit the following reports for each lease separately to the Regional Office. Initial reports for those leases in the area removed from dispute, referred to in Paragraph 3 above, shall be for the month of April 1972 for the reports required in A, C, and D, below, and for the quarter ending April 1, 1972, for the report required in B below.

A. A monthly well potential report on a form identical to the Louisiana Department of Conservation Form DM-1R. This report shall be submitted for each month by the 10th day of each succeeding month.

B. A gas well deliverability test report on a form identical to the Louisiana Department of Conservation Form DT-1, shall be submitted by January 1, April 1, July 1, and October 1.

C. A monthly producer's crude oil and/or condensate report on a form identical to Louisiana Department of Conservation Form R-1. This report shall be submitted for each month by the 25th day of each succeeding month.

D. A monthly producer's natural gas report on a form identical to Louisiana Department of Conservation Form R-5P. This report shall be submitted for each month by the last day of each succeeding month.

5. Limitations on Production.

A. Production rates shall not result in venting or flaring of gas in violation of the Operating Regulations in 30 CFR 250.30.

B. In order to provide safe operating conditions and prevent pollution, oil and gas production rates shall not exceed the operating capacity of production, transportation, and storage facilities, including, but not limited to, separators, dehydrators, compressors, surge tanks, and pipelines. All producing operations shall be in accordance with the provisions of OCS Orders Nos. 5, 7, 8 and 9. Production rates shall be maintained at a level to permit efficient operation of subsurface safety devices.

Robert F. Evans

Robert F. Evans
Supervisor

Approved: April 5 77

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

OCS Order No. 12
August 13, 1971

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

PUBLIC INSPECTION OF RECORDS

This Interim Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.97 and 43 CFR 2.2. Sectio 250.97 of 30 CFR provides as follows:

> Public Inspection of Records. Geological and geophysical interpretations, maps, and data required to be submitted under this part shall not be available for public inspection without the consent of the lessee so long as the lease remains in effect or until such time as the supervisor determines that release of such information is required and necessary for the proper development of the field or area.

Section 2.2 of 43 CFR provides in part as follows:

> Determinations as to Availability of Records. (a) Section 552 of Title 5, U.S. Code, as amended by Public Law 90-23 (the act codifying the "Public Information Act") requires that identifiable agency records be made available for inspection. Subsection (b)[1] of section 552 exempts several categories of records from the general requirement but does not require the withholding from inspection of all records which may fall within the categories exempted. Accordingly, no request made of a field office to inspect a record shall be denied unless the head of the office or such higher field authority as the head of the bureau may designate shall determine (1) that the record falls within one or more of

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[1] Subsection (b) of section 552 provides that:

(b) This section does not apply to matters that are--

***

(4) Trade secrets and commercial or financial information obtained from a person and privileged or confidential;

***

(9) Geological and geophysical information and data, including maps, concerning wells.

the categories exempted and (2) either that disclosure is prohibited by statute or Executive Order or that sound grounds exist which require the invocation of the exemption. A request to inspect a record located in the headquarters office or a bureau shall not be denied except on the basis of a similar determination made by the head of the bureau or his designee, and a request made to inspect a record located in a major organizational unit of the Office of the Secretary shall not be denied except on the basis of a similar determination by the head of that unit. Officers and employees of the Department shall be guided by the "Attorney General's Memorandum on the Public Information Section of the Administrative Procedure Act" of June 1967.

(b) An applicant may appeal from a determination that a record is not available for inspection to the Solicitor of the Department of the Interior, who may exercise all of the authority of the Secretary of the Interior in this regard. The Deputy Solicitor may decide such appeals and may exercise all of the authority of the Secretary in this regard.

he operator shall comply with the requirements of this Order. Any depar-ures from the requirements specified in this Order shall be subject to pproval pursuant to 30 CFR 250.12(b).

1. Availability of Records Filed on or after December 1, 1970. It as been determined that certain records pertaining to leases and wells in he Outer Continental Shelf and submitted under 30 CFR 250 shall be made vailable for public inspection, as specified below, in the Area office, etairie, Louisiana.

A. Form 9-152 - Monthly Report of Operations. All information contained on this form shall be available except the information required in the Remarks column.

B. Form 9-330 - Well Completion or Recompletion Report and Log. (1) Prior to commencement of production all information contained on this form shall be available except Item la, Type of Well; Item 4, Location of Well, At top prod. interval reported below; Item 22, if Multiple Compl., How many; Item 24, Producing Interval; Item 26, Type Electric and Other Logs Run; Item 28, Casing Record; Item 29, Liner Record; Item 30, Tubing Record; Item 31, Perforation Record; Item 32, Acid, Shot, Fracture, Cement Squeeze, etc.; Item 33, Production; Item 37, Summary of Porous Zones; and Item 38, Geologic Markers.

(2) After commencement of production all information shall be available except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers.

(3) If production has not commenced after an elapsed time of five years from the date of filing Form 9-330 as required in 30 CFR 250.38(b), all information contained on this form shall be available except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers. Within 90 days prior to the end of the five-year period the lessee or operator may submit objections to the release of such information. The supervisor, taking into consideration the objections of the lessee, proximity to unleased lands and the best interests of the United States, may determine that such information shall not be released.

C. Form 9-331 - Sundry Notices and Report on Wells. (1) When used as a "Notice of Intention to" conduct operations, all information contained on this form shall be available except Item 4, Location of Well, At top prod. interval; and Item 17, Describe Proposed or Completed Operations.

(2) When used as a "Subsequent Report of" operations, and after commencement of production, all information contained on this form shall be available except information under Item 17 as to subsurface locations and measured and true vertical depths for all markers and zones not placed on production.

D. Form 9-331C - Application for Permit to Drill, Deepen or Plug Back. All information contained on this form, and location plat attached thereto, shall be available except Item 4, Location of Well, At proposed prod. zone; and Item 23, Proposed Casing and Cementing Program.

E. Sales of Lease Production. Information contained on monthly Geological Survey computer printout showing sales of production of oil, condensate, gas and liquid products, by lease, shall be made available.

2. Filing of Reports. All reports on Forms 9-152, 9-330, 9-331, and 9-331C shall be filed in accordance with the following:

A. All reports submitted on these forms after the effective date of this Order shall be filed in two separate sets. All items on the forms in one set shall be completed in full and such forms, and all attachments thereto, shall not be available for public inspection. The additional set shall be completed in full, except that the items described in 1.(A), (B), (C), and (D) above, and the attachments relating to such items, may be excluded. The words "Public Information" shall be shown on the lower right-hand corner of this set. This additional set shall be made available for public inspection.

B. Copies of reports on these forms which were filed between December 1, 1970, and the effective date of this Order, shall be resubmitted (in duplicate or triplicate, as provided by the regulations) within 30 days after the effective date of this Order. These reports may exclude the items described in 1. (A), (B), (C), and (D) above, and shall show the words "Public Information" on the lower right-hand corner and shall be made available for public inspection.

3. Availability of Records Filed Prior to December 1, 1970. Information filed prior to December 1, 1970, on the forms referred to in (1) above, is not in a form which can be readily made available for public inspection. Requests for information on these forms shall be submitted to the supervisor in writing and shall be made available in accordance with 43 CFR Part 2.

Robert F Evans
Robert F. Evans
Supervisor

Aproved: August 13, 1971 ✓

Russell G. Wayland
Rssell G. Wayland
Cief, Conservation Division

Notice to Lessees and Operators
of
Federal Oil and Gas Leases
in the
Outer Continental Shelf
Pacific Region

OCS ORDERS

UNITED STATES
DEPARTMENT OF THE INTERIOR

GEOLOGICAL SURVEY
CONSERVATION DIVISION

Branch of Oil and Gas Operations
Pacific Region

OCS Order No. 2
June 1, 1971

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION

DRILLING PROCEDURES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.34, 250.41, and 250.91. All exploratory wells drilled for oil and gas shall be drilled in accordance with the provisions of this Order. Initial development wells drilled for oil and gas shall be drilled in accordance with the provisions of this Order, and these provisions shall continue in effect until field rules are issued. After field rules have been established by the Supervisor, development wells in the individual fields shall be drilled in accordance with such rules.

Where sufficient geologic and engineering information is obtained through exploratory drilling, operators may make application to the Supervisor for the establishment of field rules, but such applications shall be made before more than five development wells have been drilled in a field. When required by the Supervisor, operators shall make application for the establishment of field rules for existing fields containing more than five development wells on the date of this Order.

Each Application to Drill (Form 9-331C) for exploratory wells and development wells not covered by field rules shall include all information required under 30 CFR 250.91 and the detailed casing, cementing, mud, and blowout prevention program for the well and shall comply with the following requirements. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. Well Casing. All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1). The Application to Drill (Form 9-331C) shall contain a statement that all zones which contain oil, gas, or fresh water shall be fully protected by casing and cement. All casing strings shall be new pipe or equivalent. For the purpose of this Order, the several casing strings in order of normal installation are drive or structural casing, conductor casing, surface casing, intermediate casing, protective casing, and production casing. These casing strings shall be run and cemented prior to drilling below the specified setting depths, subject to minor variations to permit the casing to be set in a competent bed. All depths refer to true vertical depth (TVD) below the ocean floor, unless otherwise specified. Determination

of proper casing setting depths shall be based upon all geological and engineering factors including the presence or absence of hydrocarbons. Formation fracture gradients and formation pressures shall be taken into account.

A. *Drive or Structural Casing.* This casing shall be set by drilling, driving, or jetting to a depth of approximately 100 feet below the ocean floor to support unconsoliuated deposits and to provide hole stability for initial drilling operations. If drilled in, the drilling fluid shall be a type that will not pollute the ocean. This casing may be omitted, when approved by the Supervisor, if there is geological evidence that hydrocarbons will not be encountered while drilling the hole for the conductor casing and is not needed for hole stability.

B. *Conductor Casing.* This casing shall be set at a minimum depth of 300 feet or a maximum depth of 500 feet below the ocean floor; provided, however, the conductor casing shall be set before drilling into shallow formations known to contain oil or gas or, if unknown, upon encountering such formations.

C. *Surface Casing.* This casing shall be set at a minimum depth of 1,000 feet or a maximum depth of 1,200 feet below the ocean floor, but may be set as deep as 1,500 feet in the event the conductor casing is set at least 450 feet below the ocean floor.

D. *Intermediate Casing.* This casing shall be set if the proposed total depth of the well is greater than 3,500 feet (TVD in feet from rotary table). When surface casing is set at 1,500 feet the intermediate casing may be omitted if the proposed total depth of the well is not greater than 4,500 feet. Otherwise, the intermediate casing shall be set before drilling below the setting depths specified in the following table:

Proposed Total Depth of Well or Proposed Depth of First Full String of Protective Casing (TVD in feet from Rotary Table)	Setting Depths for Intermediate Casing (TVD in Feet Below Ocean Floor)	
	Minimum	Maximum
3,500 - 4,500	1,500	3,500
4,500 - 6,000	1,750	3,500
6,000 - 9,000	2,250	3,500
9,000 - 11,000	2,750	3,500
11,000 - 13,000	3,250	3,500
13,000 - Below	3,450	3,550

E. *Protective Casing.* When required by well conditions, this casing shall be set at any time when drilling below the surface casing. If a liner is used as a protective string, the lap shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and next larger string has been achieved. The test shall be recorded on the driller's log and shall be witnessed by a Geological Survey representative.

F. *Production Casing.* This casing shall be set before completing the well for production. When a blank or combination liner is run and cemented as production casing, the testing of the lap between the liner top and next larger string shall be conducted as in the case of protective liners. The surface casing shall never be used as production casing.

G. *Casing Cementing.* The structural (if drilled or jetted), conductor, and surface casings shall be cemented with a quantity sufficient to fill the annular space back to the ocean floor. The intermediate casing shall be cemented with a quantity sufficient to fill the annular space back to the ocean floor or at least 100 feet into the next larger string of pipe. The protective casing shall be cemented so that all hydrocarbon zones and abnormal pressure intervals are isolated. The production casing shall be cemented in a manner necessary to cover or isolate all zones which contain hydrocarbons and abnormal pressure intervals, but in any case, a calculated volume sufficient to fill the annular space at least 500 feet above the uppermost hydrocarbon zone, not previously cased, must be used. Whenever there are indications of improper cementing, such as lost circulation, cement channeling, or mechanical failure of equipment, a temperature or cement bond survey shall be run, either before or after remedial cementing, to aid in determining whether the casing is properly cemented. If the annular space is not adequately cemented by the primary operation, the operator shall either (1) recement, (2) squeeze the shoe of the casing with cement, either by drilling out and squeezing or by squeezing through perforations at the interval of competent formation nearest the shoe, or (3) displace with cement in sufficient quantity to fill the annular space. Upon determining that the casing shoe has been adequately cemented the operator may commence further drilling operations provided that prior to abandonment of the well the annular space behind the conductor, surface, and intermediate casings shall be cemented back to the ocean floor or 100 feet into the next larger string of pipe.

H. *Pressure Testing.* Prior to drilling the plug after cementing, all casing strings, except the drive or structural casing, shall be pressure tested as shown in the table below. This test shall not exceed the rated working pressure of the casing. If the pressure declines more than 10 percent in 30 minutes, or if there is other indication of a leak, corrective measures must be taken until a satisfactory test is obtained.

Casing String	Minimum Pressure Test (psi)
Conductor	200
Surface and Intermediate	1,000
Protective	1,500 or 0.2 psi/ft., whichever is greater
Liner	1,500 or 0.2 psi/ft., whichever is greater
Production	1,500 or 0.2 psi/ft., whichever is greater

After cementing any of the above strings, drilling shall not be commenced until a time lapse of:

(1) 24 hours, or

(2) 8 hours under pressure for the conductor casing string and 12 hours under pressure for all other casing strings. (Cement is considered under pressure if one or more float valves are employed and are shown to be holding the cement in place or when other means of holding pressure are used.)

All casing pressure tests shall be recorded on the driller's log.

2. *Blowout Prevention Equipment.* Blowout preventers and related well control equipment shall be installed, used, and tested in a manner necessary to prevent blowouts. Prior to drilling below the conductor casing, blowout prevention equipment shall be installed and maintained ready for use until drilling operations are completed as follows:

A. Conductor Casing. Before drilling below this string, at least one remotely controlled hydril type blowout preventer and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed. To avoid formation fracturing from complete shut-in of the well, a pipe of adequate diameter with control valves shall be installed below the blowout preventer so as to permit the diversion of hydrocarbons and other fluids; except that when the blowout preventer assembly is on the ocean floor, the choke and kill lines shall be equipped to permit the diversion of hydrocarbons and other fluids.

B. Surface Casing. Before drilling below this string the blowout prevention equipment shall include a minimum of:

(1) three remotely controlled, hydraulically operated blowout preventers with a rated working pressure which exceeds the maximum anticipated surface pressure, including one equipped with pipe rams, one with blind rams, and one hydril type;

(2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body;

(3) a choke manifold;

(4) a kill line; and

(5) a fill-up line.

C. Intermediate Casing. Before drilling below this string the blowout prevention equipment shall include a minimum of:

(1) four remotely controlled, hydraulically operated blowout preventers with a rated working pressure which exceeds the maximum anticipated surface pressure, including at least one equipped with pipe rams, one with blind rams, and one hydril type;

(2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body;

(3) a choke manifold;

(4) a kill line; and

(5) a fill-up line.

D. Testing. Ram-type blowout preventers and related control equipment shall be tested to the rated working pressure of the stack assembly or to the working pressure of the casing, whichever is the lesser, at the following times:

(1) when installed;

(2) before drilling out after each string of casing is set;

(3) not less than once each week while drilling; and

(4) following repairs that require disconnecting a pressure seal in the assembly. The hydril type blowout preventer shall be tested to 70 percent of the above pressure requirements.

While drill pipe is in use ram-type blowout preventers shall be actuated to test proper functioning once each trip, but in no event less than once each day. The hydril type blowout preventer shall be actuated on the drill pipe once each week. Accumulators or accumulators and pumps shall maintain a reserve capacity at all times to provide for repeated operation of hydraulic preventers. A blowout prevention drill shall be conducted weekly for each drilling crew to insure that all equipment is operational and that crews are properly trained to carry out emergency duties. All blowout preventer tests and crew drills shall be recorded on the driller's log.

E. Other Equipment. An inside blowout preventer assembly (back pressure valve) and a full opening drill string safety valve in the open position shall be maintained on the rig floor at all times while drilling operations are being conducted. Valves shall be maintained on the rig floor to fit all pipe in the drill string. Also, a socket type, sealing coupling capable of being dropped over exposed drill pipe with a full opening safety valve above it shall be maintained on the rig floor for control situations where flow prevents installation of a safety valve. A top kelly cock shall be installed below the swivel and another at the bottom of the kelly of such design that it can be run through the blowout preventers.

3. *Mud Program - General.* The characteristics, use, and testing of drilling mud and the conduct of related drilling procedures shall be such as are necessary to prevent the blowout of any well. Quantities of mud materials sufficient to insure well control shall be maintained readily accessible for use at all times.

   A. *Mud Control.* Before starting out of the hole with drill pipe, the mud shall be circulated with the drill pipe just off bottom until the mud is properly conditioned. Proper conditioning requires, at a minimum, circulation to the extent that the annulus volume is displaced. When coming out of the hole with drill pipe, the annulus shall be filled with mud before the mud level drops below 100 feet, and a mechanical device for measuring the amount of mud required to fill the hole shall be utilized. The volume of mud required to fill the hole shall be watched, and any time there is an indication of swabbing or influx of formation fluids, the necessary safety device(s) required in subparagraph 2.E. above shall be installed on the drill pipe, the drill pipe shall be run to bottom and the mud properly conditioned. The mud shall not be circulated and conditioned except on or near bottom, unless well conditions prevent running the pipe to bottom. The mud in the hole shall be circulated or reverse circulated prior to pulling drill stem test tools from the hole.

   B. *Mud Testing Equipment.* Mud testing equipment shall be maintained on the drilling platform at all times, and mud tests consistent with good operating practice shall be performed daily, or more frequently as conditions warrant.

   The following mud system monitoring equipment must be installed (with derrick floor indicators) and used throughout the period of drilling after setting and cementing the conductor casing:

579

(1) Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include a visual or audio warning device.

(2) Mud volume measuring device for accurately determining mud volumes required to fill the hole on trips.

(3) Mud return or full hole indicator to determine when returns have been obtained, or when they occur unintentionally, and additionally to determine that returns essentially equal the pump discharge rate.

D.W. Solanas

D. W. Solanas
Supervisor

Approved: June 1, 1971

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

580

OCS Order No. 4
June 1, 1971

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION

SUSPENSIONS AND DETERMINATION OF WELL PRODUCIBILITY

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.12(d)(1). An OCS lease provides for extension beyond its primary term for as long as oil or gas may be produced from the lease in paying quantities. The term "paying quantities" as used herein means production in quantities sufficient to yield a return in excess of operating costs. An OCS lease may be maintained beyond the primary term, in the absence of actual production, when a suspension of production has been approved. Any application for suspension of production for an initial period shall be submitted prior to the expiration of the term of a lease. The Supervisor may approve a suspension of production provided at least one well has been drilled on the lease and he determines it to be capable of being produced in paying quantities. The temporary or permanent abandonment of a well will not preclude approval of a suspension of production as provided in 30 CFR 250.12(d)(1). Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

A well may be determined to be capable of producing in paying quantities when the requirements below have been met.

1. Oil Wells. A deliverability test of at least two hours' duration after the well flow has stabilized which proves that the well is capable of producing oil in paying quantities.

2. Gas Wells. A four-point back pressure test or a measured deliverability test of at least two hours' duration after the well flow has stabilized which proves that the well is capable of producing gas or gas and condensate in paying quantities.

3. *Witnessing and Results.* All tests must be witnessed by an authorized representative of the Geological Survey. Test data accompanied by operator's affidavit, or third-party test data, may be accepted in lieu of a witnessed test provided prior approval is obtained from the appropriate district office. The results of the witnessed or accepted test must justify a determination that the well is capable of producing in paying quantities.

D.W. Solanas

D. W. Solanas
Supervisor

Approved: June 1, 1971

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

OCS Order No. 5
June 1, 1971

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION

INSTALLATION OF SUBSURFACE SAFETY DEVICE

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.41(b). Section 250.41(b) provides as follows:

> (b) Completed wells. In the conduct of all its operations, the lessee shall take all steps necessary to prevent blowouts, and the lessee shall immediately take whatever action is required to bring under control any well over which control has been lost. The lessee shall: (1) in wells capable of flowing oil or gas, when required by the supervisor, install and maintain in operating condition storm chokes or similar subsurface safety devices; (2) for producing wells not capable of flowing oil or gas, install and maintain surface safety valves with automatic shut-down controls; and (3) periodically test or inspect such devices or equipment as prescribed by the supervisor.

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. All wells capable of flowing oil or gas shall be equipped with a subsurface safety device installed at a depth of 100 feet or more below the ocean floor. Such device shall be installed in all oil and gas wells, including artificial lift wells, unless proof is provided to the Supervisor that such wells are incapable of any natural flow. For shut-in wells capable of flowing oil or gas, a tubing plug may be installed, in lieu of a subsurface safety device, and such plug shall be installed when required by the Supervisor.

2. Subsurface safety devices shall be adjusted, installed, and maintained to insure reliable operation. Each subsurface safety device and tubing plug installed in a well shall be

tested at intervals not exceeding 6 months. Where a safety valve is set in a landing nipple and is of the type that is controlled from the surface by a hydraulic line or other means, the valve may be tested from the surface to insure proper functioning. If the valve does not operate properly it shall be removed, repaired, reinstalled or replaced and again checked for proper operation.

When a subsurface safety device is removed from a well for repair or replacement, a standby subsurface safety device or tubing plug shall be available at the well location. In the event of an emergency such device shall be immediatcly installed within the limits of practicability, consideration being given to time, equipment, and personnel safety.

Subsurface safety devices that are an integral part of the tubing string shall be tested at intervals not exceeding six months and, if the test is unsatisfactory, shall be replaced or a removable subsurface device shall be installed.

All wells in which a subsurface safety device or tubing plug is installed shall have the tubing-casing annulus sealed below the valve or plug setting depth.

3. In all tubing installations made after the effective date of this Order, the tubing string shall be equipped with a surface-controlled subsurface safety device. In high-flow-rate wells or wells producing sand, areas of turbulence above and below such devices shall be protected by flow couplings or other protective equipment. Wells which are presently equipped with direct-controlled subsurface safety devices shall have surface-controlled subsurface safety devices installed the first time the tubing is pulled after the effective date of this Order, or within one year after the effective date of this Order, whichever occurs sooner. The control system for the surface-controlled subsurface safety devices shall be an integral part of the platform shut-in system.

4. The well completion report on Form 9-330 and any subsequent report of workover on Form 9-331 shall state the type and the depth of the subsurface safety device or tubing plug installed in the well or state that the requirement has been waived.

5. The operator shall maintain records, available at a structure in the field to any authorized representative of the Geological Survey, showing the present status and past history of each subsurface safety device or tubing plug, including dates and details of inspection, testing, repairing, adjustment and reinstallation or replacement. The operator shall submit a copy of such records semiannually to the District Engineer.

D.W. Solanas

D. W. Solanas
Supervisor

Approved: June 1, 1971

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

OCS Order No. 10
June 1, 1971

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
BRANCH OF OIL AND GAS OPERATIONS
PACIFIC REGION

NOTICE TO PERMITTEES OF TWIN CORE HOLE PERMITS IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION

DRILLING OF TWIN CORE HOLES

The Secretary of the Interior on November 3, 1965, approved the drilling of core holes on unleased lands of the Outer Continental Shelf off the coast of Southern California (30 Federal Register No. 218, Nov. 10, 1965). Authority was delegated to the Regional Oil and Gas Supervisor of the U. S. Geological Survey to approve the drilling of such wells provided (1) the core hole to be drilled is located within 100 feet of a well heretofore drilled under a State permit, or such greater distance from such a well as the Supervisor may prescribe where the prior drilled well is less than three geographical miles from the coastline, (2) the maximum depth to which a core hole may be drilled shall be the depth of the prior drilled well, (3) the approvals to drill core holes granted by the Supervisor shall be conditioned upon compliance with the regulations in 30 CFR Part 250, and such other reasonable requirements as he may prescribe, and (4) no approval to drill shall be granted until the applicant has posted an acceptable corporate surety bond in the amount prescribed in 43 CFR 3304.1, conditioned on compliance with all the requirements set forth in the permits to drill granted by the Supervisor.

In addition to the above, the permittee shall comply with the following requirements:

1. OCS Orders No. 1, 2, 3, 7, and 8 are hereby made applicable to core drilling operations.

2. An application for a general permit to conduct core drilling shall have been filed for approval prior to the filing of any applications to drill specific core holes.

3. A $300,000 corporate surety bond (Form 3380-3) covering Pacific Coast OCS operations shall have been filed.

4. Each application to drill a core hole (Form 9-331C in triplicate) shall be held in an open file in the Supervisor's office for 15 days after filing before approval may be granted. Only the application shall be considered public information.

5. The permittee shall: (a) obtain or have a geological survey blanket permit from the State to drill core holes within State waters, (b) obtain appropriate permission from the Army Corps of Engineers for the location of drilling ships (as provided in the Secretary of the Interior's Notice in 18 FR No. 186, Sept. 23, 1953).

6. All core hole locations shall be described by the Lambert Coordinate System for reference purposes applicable to the location in which it falls.

7. In each application to drill a twin core hole, the original State-permitted core hole shall be identified.

8. The permittee shall file a statement as to the exact location of the surface of the approved core hole and certify that it is within 100 feet of the original core hole at such time as drilling commences.

9. No directionally drilled core holes will be permitted.

10. Mud log and gas detector equipment shall be in operation while drilling below the shoe of the surface casing on twinned holes and below the shoe of the conductor casing on core holes offsetting the three-mile line not being drilled as a twin.

11. No down-hole formation fluid sampling equipment shall be operated at any time.

12. Conventional coring will be permitted either to total approved depth or such lesser depth as prescribed by the Supervisor provided the permittee of the original core hole being twinned has not filed an affidavit with the Supervisor stating that no conventional coring had been conducted in the original core hole. Sidewall sample coring may be conducted in that part of the hole in which an electric log has been run. Upon completion of operations the permittee shall file with the Supervisor a duly attested duplicate copy of the contractor's original log (tour sheet).

13. The permittee shall advise the District Engineer, Geological Survey, at least 48 hours prior to the drilling and reaching of the approved total depth. The "measuring out" of drill pipe at total depth will be witnessed by the District Engineer or his representative.

14. The permittee shall not commence any abandonment operations prior to obtaining written approval from the District Engineer, Geological Survey. Abandonment of the core hole and clearing of the location of all obstructions on the ocean floor shall be witnessed by a representative of the Geological Survey.

15. Such other requirements as shall be prescribed in the general permit or the specific approved core hole application, or at any time such additional requirements are deemed necessary by the Supervisor or his representative.

D.W. Solanas

D. W. Solanas
Supervisor

Approved: June 1, 1971

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

ATTACHMENT C

Notices

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications d agency statements of organization and functions are examples of documents appearing in this section.

ARTMENT OF THE INTERIOR

Bureau of Land Management

NTIAL FUTURE OUTER CONTI- AL SHELF OIL AND GAS LEASING

Request for Comments

order to implement President Nix- irective to lease ten million acres in and in order to implement more the purposes and objectives of the Continental Shelf Lands Act, all med parties representing the oil as industry and the general public vited and encouraged to submit in- tion concerning areas of interest shore oil and gas leasing and to y problem areas. This is being done er to help ensure that scarce re- s for exploration and development employed on the most promising consistent with environmental ards. Regulations or procedures ary to implement the other actions nced by the President in his Message relating to Outer Con- l Shelf (OCS) leasing will be sub- tly published for public comment they become effective and are not this request for comment.

and gas resources of the con- l margin, including those be- he 200 meter depth contour, sub- jurisdiction of the United States be considered. Precise continental oundaries between the U.S. and e or adjacent states have not, ome exceptions, been agreed. Ac- gly certain areas are or may be to dispute. No decision has been o undertake leasing in actually or lally disputed areas while efforts ng made to reach agreement with tions concerned. In this connection ice is made to the last sentence of ment of State Public Notice 320, ing in 35 FR 2301 of February 20,

ing in the Cook Inlet of Alaska the Atlantic OCS is contingent on ion of the litigation between the l Government and the State of and Atlantic coastal states re- areas of jurisdiction or an alter- resolution of the issues. Further, esident's Council on Environmen- ality is conducting studies of the mental impact of oil and gas pro- on the continental shelf of the c Ocean and the Gulf of Alaska. sing in these areas will be per- unless it is determined that oil exploration and development can in an environmentally satisfac- anner. However, information con- OCS areas of interest is being requested at this time in order to identify areas of special resource potential and of environmental value. It is the intention of the Department of Interior to conduct a call for tract nominations on more specific areas after consideration of the comments resulting from this request and, where appropriate, after resolution of State/Federal jurisdiction disputes and a determination from [illegible] OCS Atlantic and Gulf of Alaska [illegible] that development can proceed in these areas in an environmentally satisfactory manner. Information received in response to this request will also be considered in determining future leasing policies.

The areas to be commented on are as follows:

	Approximate location
Atlantic Coast OCS areas:	
1. North Atlantic	Bay of Fundy to Cape Cod north of 40° N latitude and south of.[1]
2. Mid-Atlantic	Cape Cod to Cape Hatteras between 40° N to 35° N. latitude.
3. South Atlantic	Cape Hatteras to Key West south of 35° N latitude.
Gulf of Mexico OCS areas:	
4. East Gulf	East of 88° W. longitude.
5. Central Gulf	Between 88° W. to 93° W. longitude.
6. West Gulf	West of 93° W. longitude to Mexican border.
Pacific OCS areas:	
7. Southern California Borderland	South of 34° N. latitude to Mexican border (except Santa Barbara Channel).
8. Santa Barbara	Santa Barbara Channel.
9. North and Central California	North of 34° N. latitude to California-Oregon border (except Santa Barbara Channel).
10. Washington-Cregon	Between California-Oregon border and Canadian border.
Alaska OCS areas:	
11. Cook Inlet	South of 60° N. latitude.
12. Southern Aleutian Shelf	West of 153° W. longitude.
13. Gulf of Alaska	North of 56° N. latitude, east of 153° W. longitude.
14. Bristol Bay	South of 58° N. latitude, east of 165° W. longitude.
15. Bering Sea Shelf	U.S. waters south of 66° N. latitude
16. Beaufort Sea	Between 142° W. and 160° W. longitude.
17. Chukchi Sea	U.S. waters north of 66° N. latitude, west of 160° W. longitude.

[1] The line drawn from a point at:
42°19.9′ N. latitude, 67°46.9′ W. longitude, thence to 42°9.3′ N. latitude, 6[illegible]°40.0′ W longitude, thence 41°42.4′ N. latitude. 67°28.8′ W. longitude, and ending at 41°15.3′ N. latitude, 66°58.9′ W. longitude.

Other Areas of interest may be commented upon by appropriate area designation.

AREAS OF OIL AND GAS RESOURCE POTENTIAL

The following information is requested:

1. Rank by order of oil and gas potential the areas of interest listed above.

2. Outline of geologic structures of areas of interest shown on appropriate maps. All such information will remain confidential on request. Bureau of Land Management official leasing maps may be obtained from: (1) Gulf of Mexico Outer Continental Shelf Office, Suite 3200, The Plaza Tower, 1001 Howard Avenue, New Orleans, Louisiana 70113; (2) Pacific Outer Continental Shelf Office, 300 North Los Angeles Street, Los Angeles, California 90012; or, (3) Alaska Outer Continental Shelf Office, 121 W Firewood Lane, Room 2[illegible]0, P.O. Box 1159, Anchorage, Alaska 99501.)

3. For each area of interest, estimated time periods required to achieve initial and peak production after a discovery is made, and identification of specific factors that may constrain development for these areas.

AREAS OF ENVIRONMENTAL CONCERN

The following information is requested:

1. Rank with areas of greatest environmental concern first the above areas and indicate specific environmental values which exist and damages which might be incurred.

2. If possible, indicate the location on maps of specific environmental features or hazards to be considered in these areas if their resource potential is devel-

oped (locations where maps can be obtained listed above).

3. Indicate specific actions which may be taken to reduce or eliminate potential conflicts with oil and gas exploration and development activities.

The information should be submitted no later than May 1, 1974, in envelopes or packets marked "Request for Comments on Potential Future, Outer Continental Shelf Oil and Gas Leasing." The information should be submitted to Director, Attention 730, Bureau of Land Management, Washington, D.C. 20240. Copies of the information should also be sent to the Chief, Conservation Division, No. 600, U.S. Geological Survey, National Center, Reston, Virginia 22092.

George C. Turcott,
Associate Director,
Bureau of Land Management.

Approved: February 15, 1974.

John C. Whitaker,
Acting Secretary of the Interior.

[FR Doc.74-4126 Filed 2-15-74;4:51 pm]

[Wyoming 0310786]

WYOMING

Opening Land to Small Tract Application

February 11, 1974.

1. Pursuant to Small Tract Classification Wyoming 0310786 dated September 14, 1971, the following described land will be opened to small tract application as set out below, for sale under the Small Tract Act of June 1, 1938, as amended; 43 U.S.C. 682a–e (1970):

Sixth Principal Meridian, Wyoming

T. 40 N., R. 78 W.,
sec. 30, lot 7.

The above described parcel contains 4.79 acres.

The land is located in Natrona County near Midwest, Wyoming. It is bordered on the east and south by U.S. Highway 87 and State Highway 387.

2. At 10 a.m. on February 21, 1974, the land will be open to applications to purchase the lot under the Small Tract Act. All valid applications received at or prior to 10 a.m. on February 21, 1974, will be considered as simultaneously filed at that time. All applications filed after that time will be considered in the order of filing.

3. Applicants must file, in duplicate, with the Chief, Lands and Mining Section, Bureau of Land Management, PO Box 1828, Cheyenne, Wyoming, application Form 2730–1 filled out in compliance with instructions on the form. The application must be accompanied by a relinquishment of the existing small tract lease W-0310786 embracing the land, conditioned upon conveyance of title. Copies of the application form can be secured from the above-named official. The application must be accompanied by a filing fee of $10 and the purchase money for the land in the amount of $29,000. Failure to transmit these payments with the application will render the application invalid. Advance purchase payments will be returned to unsuccessful applicants. All filing fees will be retained by the United States.

4. The patent (the title transfer document), when it issues, will contain a reservation of all minerals to the United States, and will be subject to rights-of-way of record and the rights of prior oil and gas permittees.

Daniel P. Baker,
State Director.

[FR Doc.74-3938 Filed 2-19-74;8:45 am]

National Park Service

CHESAPEAKE AND OHIO CANAL NATIONAL HISTORICAL PARK COMMISSION

Notice of Meeting

Notice is hereby given in accordance with the Federal Advisory Committee Act that a meeting of the Chesapeake and Ohio Canal National Historical Park Commission will be held on Saturday, February 23, 1974, at 9 a.m., at the Stephen Mather Training Center, Harpers Ferry, West Virginia.

The Commission was established by Pub. L. 91–664 to meet and consult with the Secretary of the Interior on general policies and specific matters related to the administration and development of the Chesapeake and Ohio Canal National Historical Park.

The members of the Commission are as follows:

Miss Nancy Long, Glen Echo, Maryland (Chairman)
Mrs. Caroline Freeland, Bethesda, Maryland
Hon. Vladimir A. Wahbe, Baltimore, Maryland
Mr. John C. Lewis, Hamilton, Virginia
Mr. Burton C. English, Berkeley Springs, W. Va.
Mr. James G. Banks, Washington, D.C.
Mr. Joseph H. Cole, Washington, D.C.
Mrs. Dorothy Grotos, Arlington, Virginia
Mr. Anthony Abar, Annapolis, Maryland
Mr. Ronald A. Clites, LaVale, Maryland
Mrs. Mary Miltenberger, Cumberland, Maryland
Dr. James H. Gilford, Frederick, Maryland
Mr. Grant Conway, Brookmont, Maryland
Mr. Edwin F. Wesely, Chevy Chase, Maryland
Mr. John C. Frye, Gapland, Maryland
Mr. Justice Douglas, Washington, D.C. (Special Consultant)
Mr. Rome F. Schwagel, Keedeysville, Maryland
Mr. Donald Frush, Hagerstown, Maryland

The matters to be discussed at this meeting include:

1. Dickerson Report.
2. Cumberland Report.
3. Superintendent's Report.
4. Status of the Master Plan.
5. Special Use Permits.
6. Status of Land Acquisition Program.
7. Report—Fort Duncan Historical Site.

The meeting will be open to the public. However, facilities and space for accommodating members of the public are limited and it is expected that not more than 15 persons will be able to attend the sessions. Any member of the public may file with the Commission a written statement concerning the matters to be discussed.

Persons wishing further information concerning this meeting, or who wish to submit written statements, may co Richard L. Stanton, Assistant Dir Cooperative Activities, National Ca Parks, at 202–426–6715. Minutes o meeting will be available for publi spection two weeks after the meeti the Office of National Capital P Room 208, 1100 Ohio Drive, SW, W ington, D.C.

Date: February 13, 1974.

Robert M. Landau
Liaison Officer, Advisory Co missions, National Park Se ice.

[FR Doc.74-3988 Filed 2-19-74;8:45 a

DEPARTMENT OF AGRICULTU

Forest Service

BEARTOOTH WILDERNESS, ABSA WILDERNESS, AND CUT-OFF M TAIN WILDERNESS

Notice of Proposed Establishmen

Notice is hereby given in accord with the provisions of the Act of Sep ber 3, 1964 (78 Stat. 890–892 (16 U 1131–1132)), that a public hearing be held, beginning at 9 a.m. on Marc 1974, in the Cody Club Auditorium, Wyoming; on March 29, 1974, in Petro Theatre, Eastern Montana Co Billings, Montana; and March 30, in Winans School Auditorium, 1015 Clark, Livingston, Montana, on a posal for a recommendation to be by the Secretary of Agriculture to President of the United States th recommendation be submitted to Congress for establishment of the tooth Wilderness, Absaroka Wilder and Cut-off Mountain Wilderness, prised of 516,815 acres. The prop Beartooth, Absaroka, and Cut-off M tain Wildernesses are located in Custer and Gallatin National Fores the Counties of Carbon, Park, Stillw and Sweet Grass, Montana.

A brochure containing a map and formation about the proposed Wi nesses may be obtained from the fol ing:

Custer National Forest, 2602 1st Av North, Billings, Montana 59103.
Gallatin National Forest, Federal Buil Bozeman, Montana 59715.
Regional Forester, Northern Region, Fe Building, Missoula, Montana 59801.

Individuals and organizations may press their views by appearing at hearings or, following the hearings, submit written comments for incl in the official record to the Regi Forester, Federal Building, Miss Montana 59801, by April 30, 1974.

Those wishing to present oral st ments at the hearings should notify Regional Forester, Federal Buil Missoula, Montana 59801, by Marc 1974, stating at which hearing loca the views will be expressed.

Dated: February 13, 1974.

John R. McGuire,
Chief, Forest Servic

[FR Doc.7[illegible] Filed 2-19-74;8:45 am

ATTACHMENT D

Notices

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices f hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and nd agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF DEFENSE

Office of the Secretary

DEPARTMENT OF DEFENSE WAGE COMMITTEE

Notice of Closed Meetings

Pursuant to the provisions of section 10 of Public Law 92–463, effective January 5, 1973, notice is hereby given that meetings of the Department of Defense Wage Committee will be held on:

Tuesday April 2, 1974
Tuesday April 9, 1974
Tuesday April 16, 1974
Tuesday April 23, 1974
Tuesday April 30, 1974

These meetings will convene at 9:45 a.m. and will be held in Room 1E–801, The Pentagon, Washington, D.C.

The Committee's primary responsibility is to consider and make recommendations to the Assistant Secretary of Defense (Manpower and Reserve Affairs) on all matters involved in the development and authorization of wage schedules for Federal prevailing rate employees pursuant to Public Law 92–392.

At these scheduled meetings, the Committee will consider wage survey specifications, wage survey data, local reports and recommendations, statistical analyses and proposed pay schedules derived therefrom.

Under the provisions of section 10(d) of Public Law 92–463 and 5 USC 532(b) and (4), the Assistant Secretary of Defense (Manpower and Reserve Affairs) has determined that these meetings will be closed to the public.

However, members of the public who may wish to do so, are invited to submit material in writing to the Chairman concerning matters felt to be deserving of the Committee's attention. Additional information concerning these meetings may be obtained by contacting the Chairman, Department of Defense Wage Committee, Room 3D–281, The Pentagon, Washington, D.C.

MAURICE W. ROCHE,
Director, Correspondence and
Directives, OASD(C).

MARCH 19, 1974.

[FR Doc.74–6618 Filed 3-21-74;8:45 am]

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

OUTER CONTINENTAL SHELF RESEARCH ADVISORY BOARD

Establishment and Functions

This notice is issued in accordance with the provisions of 5 U.S.C. 552(a)(1), and section 9(a)(2) of the Federal Advisory Committee Act (Public Law 92–463). The Secretary of the Interior has established an Outer Continental Shelf Research Advisory Board after consultation with the Office of Management and Budget, in accordance with the provisions of the Federal Advisory Committee Act (Public Law 92–463). The Office of Management and Budget Committee Management Secretariat has authorized a 7-day period in lieu of the required 30-day period between FEDERAL REGISTER publication of the Board charter, and its filing as prescribed in Section 9(c) of Public Law 92–463. This Board will advise the Assistant Secretary—Land and Water Resources, the Director of the Bureau of Land Management, and other Departmental officers in matters related to environmental baseline and monitoring studies on the Federal Outer Continental Shelf lands. The Board charter is published in its entirety below. Further information regarding this document may be obtained from Mr. Frederick N. Ferguson, Assistant Solicitor-Minerals, Office of the Solicitor, U.S. Department of the Interior, Washington, D.C. 20240, telephone (202) 343–4325.

Dated: March 20, 1974.

JOHN C. WHITAKER,
Under Secretary of the Interior.

CHARTER

OUTER CONTINENTAL SHELF RESEARCH MANAGEMENT ADVISORY BOARD

1. There is hereby established, pursuant to the provisions of the Federal Advisory Committee Act (5 U.S.C. 1970 ed., Supp. II, App. I), an Outer Continental Shelf Research Management Advisory Board. The Board will advise officers of the Department in the performance of discretionary functions of the Department under the Outer Continental Shelf Lands Act (43 U.S.C. §§ 1331–1343) in connection with baseline environmental data gathering and environmental monitoring on the Outer Continental Shelf (OCS). The functions of the Board are solely advisory.

2. The objective of the Board is to advise the Assistant Secretary—Land and Water Resources, the Director, Bureau of Land Management (BLM) and other officers of the Department, in the design and implementation of environmental research projects related to oil and gas exploration and development on the OCS. The objectives of the OCS program are: (1) Orderly resource development, (2) protection of the environment, and (3) receipt of fair market value. This Board through its advisory efforts will assist the Bureau in meeting objectives (1) and (2). In order to fully realize its potential, it is anticipated that the Board will be required for the duration of OCS environmental baseline research and monitoring studies, a period of approximately ten years. The Board will, however, terminate on December 31, 1975, unless prior to that date it is renewed for an additional period by the Secretary of the Interior, acting within his discretion and in accordance with the provisions of section 14(a)(2) of the Federal Advisory Committee Act, supra.

3. The Board will report directly to the Assistant Secretary-Land and Water Resources. (a) The Assistant Secretary-Land and Water Resources shall, after consultation with the Assistant Secretary-Energy and Minerals and the Assistant Secretary for Fish, Wildlife and Parks, appoint an employee of the Department of the Interior as Chairman for the Board. The Assistant Secretary-Land and Water Resources shall be responsible for assuring that the Board operates within statutory and Departmental requirements for the management of advisory committees. The Director, BLM, shall provide administrative support. (b) Each of the following Departmental bureaus shall appoint one member to the Board: The Geological Survey, and the Bureau of Sport Fisheries and Wildlife. The Administrator of the Environmental Protection Agency and the Administrator of the National Oceanic and Atmospheric Administration may each appoint one member. (c) At the invitation of the Secretary of the Interior, the Governor of each State off the coast of which OCS research projects are scheduled may nominate for appointment by the Secretary one member who shall represent that State on the Board. Initially the Governors of Mississippi, Alabama, and Florida will be asked to nominate Board members. As OCS research projects expand into other geographic areas the Governors of the respective States involved may be invited to nominate members for appointment to the Board. (d) Each Federal member shall serve until his resignation, the termination of the Board, or his removal by the officer appointing him. If the agency appointing a member removes that member, it may appoint another in his place. Each non-Federal member shall be appointed to serve a one-year term but may be reappointed for additional one-year periods if the OCS area seaward of his State is still under active research.

4. (a) Subject to the limitations imposed by this Charter, the Board may establish its own procedures for the conduct of business. To facilitate the performance of the Board's functions, the Chairman may establish committees composed of members of the Board. Most scheduled meetings will be of specific committees, but the Chairman will have the latitude to invite any individual State member to any committee meeting. (b) The Board shall prepare an annual report to the Secretary on the status of ongoing environmental OCS research. The report will be made available to the public.

5. The Chief Scientist for the BLM OCS environmental research program or a person designated by him will attend all Board and committee meetings and will assist the Chairman wherever possible.

6. The Board will meet at the call of the Chairman, who shall give at least fifteen day's notice in writing. The Board is expected to meet at least bi-annually. Meetings will be conducted in accordance with statutory and Departmental requirements for advisory committees as prescribed in 308 DM 2 of the Department of the Interior Manual.

The estimated total annual operating costs of the Board are $10,000 and one man year of staff support.

7 The formation of this committee is determined to be in the public interest in connection with the performance of duties of this Department pursuant to statute as stated in paragraph 1 above. This Charter shall become effective April 1, 1974.

Dated: March 20, 1974.

JOHN C. WHITAKER,
Under Secretary of the Interior.

[FR Doc.74-6854 Filed 3-21-74;9:43 am]

Fish and Wildlife Service

KOFA GAME RANGE

Notice of Public Hearing Regarding Wilderness Proposal

Notice is hereby given in accordance with provisions of the Wilderness Act of September 3, 1964 (P.L. 88-577:78 890-896, 16 U.S.C. 1131-1136), that a public hearing will be held beginning at 1 p.m. April 25 at the Yuma Civic and Convention Center, Yuma, Arizona, to be continued at 9 a.m. April 27 at the Phoenix Civic Plaza, Phoenix, Arizona on a proposal leading to a recommendation to be made to the President of the United States by the Secretary of the Interior regarding the desirability of including a portion of the Kofa Game Range within the National Wilderness Preservation System. The wilderness study included the entire acreage within the Kofa Game Range, which is located in Yuma County, Arizona.

A study summary containing a map and information on the Kofa Game Range may be obtained from the Refuge Manager, Kofa Game Range, Box 1032, Yuma, Arizona 85364, or the Regional Director. Bureau of Sport Fisheries and Wildlife, Box 1306, Albuquerque, New Mexico 87103.

Individuals or organizations may express their oral or written views by appearing at this hearing, or they may submit written comments for inclusion in the official record of the hearing to the Regional Director at the above address by May 28, 1974.

LYNN A. GREENWALT,
Director, Bureau of Sport Fisheries and Wildlife.

MARCH 19, 1974.

[FR Doc.74-6620 Filed 3-21-74;8:45 am]

PARKER RIVER NATIONAL WILDLIFE REFUGE

Notice of Public Hearing Regarding Wilderness Proposal

Notice is hereby given in accordance with provisions of the Wilderness Act of September 3, 1964 (Pub. L. 88-577:78 Stat. 890-896:16 U.S.C. 1131-1136), that a public hearing will be held beginning at 9:30 a.m. on April 25, in the YMCA Building, Newburyport, Massachusetts, on a proposal leading to a recommendation to be made to the President of the United States by the Secretary of the Interior regarding the desirability of including a portion of the Parker River National Wildlife Refuge within the National Wilderness Preservation System. The wilderness study included the entire acreage within the Parker River National Wildlife Refuge, which is located in Essex County, Massachusetts.

A study summary containing a map and information on the Parker River Wilderness Proposal may be obtained from the Refuge Manager, Parker River National Wildlife Refuge, Northern Boulevard, Plum Island. Newburyport, Massachusetts 01950 or the Regional Director, Bureau of Sport Fisheries and Wildlife, John W. McCormick Post Office and Courthouse, Boston, Massachusetts 02109.

Individuals or organizations may express their oral or written views by appearing at this hearing, or they may submit written comments for inclusion in the official record of the hearing to the Regional Director at the above address by May 28, 1974.

F. V. SCHMIDT,
Acting Director, Bureau of Sport Fisheries and Wildlife.

MARCH 1, 1974.

[FR Doc.74-6619 Filed 3-21-74;8:45 am]

Office of the Secretary

CHARLES A. CAMPBELL

Statement of Changes in Financial Interests

In accordance with the requirements of section 710(b)(6) of the Defense Production Act of 1950, as amended, and Executive Order 10647 of November 28, 1955, the following changes have taken place in my financial interests during the past six months:

(1) No change.
(2) No change.
(3) No change.
(4) No change.

This statement is made as of February 11, 1974.

Dated: February 11, 1974.

CHARLES A. CAMPBELL.

[FR Doc.74-6679 Filed 3-21-74;8:45 am]

[INT DES 74-32]

AUTHORIZED FRYINGPAN-ARKANSAS PROJECT, COLORADO

Notice of Availability of Draft Environmental Statement

Pursuant to section 102(2)(C) of the National Environmental Policy Act of 1969, the Department of the Interior has prepared a draft environmental statement on a proposed water supply and hydroelectric power project for the purpose of furnishing municipal, industrial and irrigation water to the water-deficient areas of the Arkansas River Basin in eastern Colorado. Written comments may be submitted to the Regional Director (address below) on or before May 6, 1974.

Copies are available for inspection
the following locations:

Office of Communications, Room 7230,
partment of the Interior, Washington,
20240, Telephone (202) 343-9247.

Office of Assistant to the Commission
Ecology, Room 7620, Bureau of Recla
tion, Department of the Interior, W
ington, D.C. 20240, Telephone (202)
4991.

Division of Engineering Support, Techn
Services Branch E&R Center, Denver
eral Center, Denver, Colorado 80225, T
phone (303) 234-3014.

Office of the Regional Director, Burea
Reclamation, Lower Missouri Reg
Building 20, Denver Federal Center, D
ver, Colorado 80225. Telephone (3
234-3779.

Fryingpan-Arkansas Project Office. Burea
Reclamation, P.O. Box 515, Pueblo, C
rado 81002, Telephone (303) 544-2200.

Pikes Peak Regional Library District, P.O.
1597, Colorado Springs, Colorado 80901

Pitkin County Public Library, 110 East M
Aspen, Colorado 81611.

Pueblo Regional Library, 100 East Abri
Avenue, Pueblo, Colorado 81004 (Rober
Roehr).

Lake County Public Library, 1115 Harri
Leadville, Colorado 80461.

Buena Vista Public Library, Box U, Bu
Vista, Colorado 81211 (Mrs. Ma
Thomas).

Southern Colorado State College, 2200 B
forte Boulevard, Pueblo, Colorado 8
(Edward Broadhead).

Colorado Mountain College—West Cam
Learning Resources Center, 803 Colo
Avenue, Glenwood Springs, Colorado 81

Canon City Public Library, 512 Macon
nue, P.O. Box 361, Canon City, Color
81212.

Single copies of the draft statem
may be obtained on request to the C
missioner of Reclamation or the
gional Director. In addition, copies
be purchased from the National Tec
cal Information Service, Departmen
Commerce, Springfield Virginia 22
Please refer to the statement num
above.

Dated: March 18, 1974.

WILLIAM A. VOGELY,
Acting Deputy Assistant
Secretary of the Interio

[FR Doc.74-6610 Filed 3-21-74;8:45 a

GLENN J. HALL

Statement of Changes in Financial Interests

In accordance with the requirement
section 710(b)(6) of the Defense
duction Act of 1950, as amended,
Executive Order 10647 of November
1955, the following changes have ta
place in my financial interests during
past six months:

(1) No Change.

(2) FMC Corp., Howmet Corp., Morri
Knudsen Co., General Electric Co., Ama
mated Sugar Co Idaho Power Co., First
curity Bank Corp., Union Carbide Corp.,
cific Power & Light Co., Utah Power & L
Co., Union Pacific Corp., Portland GE
Washington Water Power Co., Montana P
Co., Westinghouse Electri Corp., P
Sound Power & Lt Co., Pfizer Corp.,
conda, Gulf Oil, AT&T Co., Sawtooth De
opment Co., Arizona Public Service Co., B

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ATTACHMENT E

notices

is section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices rings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications gency statements of organization and functions are examples of documents appearing in this section.

EPARTMENT OF STATE

[Public Notice CM-C7]

L REVIEW BOARD FOR THE CEN- OR CULTURAL AND TECHNICAL CHANGE BETWEEN EAST AND ES

Postponed Meeting

eeting of the Executive Commit- e National Review Board for the or Cultural and Technical Inter- Between East and West (East- nter), announced for June 3, (FR 16908) at the Department Room 507, SA-2, has been can- e meeting site has been changed lulu, Hawaii and scheduled for 2 1974.

eeting is being postponed to take ge of the fact that several par- will be in Honolulu at that time business.

May 13, 1974.

CAROL M. OWENS,
Executive Secretary.

c.74-11469 Filed 5-17-74;8:45 am]

ARTMENT OF THE TREASURY

Office of the Secretary

Y COMMITTEE ON REFORM OF RNATIONAL MONETARY SYSTEM

Notice of Meeting

is hereby given that the Advis- mittee on Reform of the Inter- Monetary System will meet at sury Department in Washing- , on June 3, 1974.

eeting is called for the purpose lering the basic issues involved rrent international negotiations form of the international mon- tem.

rmination as required by sec-) of the Federal Advisory Com- ct (Pub. L. 92-463) has been at this meeting is for the pur- onsidering matters falling with- more of the exemptions to pub- sure set forth in 5 U.S.C. 552(b) the public interest requires such be closed to public participation.

May 16, 1974.

PAUL A. VOLCKER,
Under Secretary for
Monetary Affairs.

oc.11666 Filed 5-17-74;9:57 am]

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

OUTER CONTINENTAL SHELF; POTENTIAL FUTURE OIL AND GAS LEASING

Preparation of Environmental Impact Statement

In order to ensure that adequate consideration is given to the environmental impacts of and alternatives to implementation of the program announced by President Nixon for an increase in potential future Outer Continental Shelf (OCS) oil and gas leasing to ten million acres in 1975, the Bureau of Land Management of the Department of the Interior will prepare an environmental impact statement for the proposed action pursuant to the provisions of section 102(2)(C) of the National Environmental Policy Act (42 U.S.C. 4332(2)(C)). OCS areas which may be affected by the proposed program include the following:

	Approximate location
Atlantic Coast OCS areas:	
1. North Atlantic	Bay of Fundy to Cape Cod north of 40° N. latitude and south of.[1]
2. Mid-Atlantic	Cape Cod to Cape Hatteras between 40° N. to 35° N. latitude.
3. South Atlantic	Cape Hatteras to Key West south of 35° N. latitude.
Gulf of Mexico OCS areas:	
4. East Gulf	East of 88 W. longitude.
5. Central Gulf	Between 88° W. to 93° W. longitude.
6. West Gulf	West of 93° W. longitude to Mexican border.
Pacific OCS areas:	
7. Southern California Borderland	South of 34° N. latitude to Mexican border (except Santa Barbara Channel).
8. Santa Barbara	Santa Barbara Channel.
9. North and Central California	North of 34° N. latitude to California-Oregon border (except Santa Barbara Channel).
10. Washington-Oregon	Between California-Oregon border and Canadian border.
Alaska OCS areas:	
11. Cook Inlet	South of 60° N. latitude.
12. Southern Aleutian Shelf	West of 153° W. longitude.
13. Gulf of Alaska	North of 56° N. latitude, east of 153° W. longitude.
14. Bristol Bay	South of 58° N. latitude, east of 165° W. longitude.
15. Bering Sea Shelf	U.S. Waters south of 66° N. latitude.
16. Beaufort Sea	Between 142° W. and 160° W. longitude.
17. Chukchi Sea	U.S. waters north of 66° N. latitude, west of 160° W. longitude.

It is the intention of the Bureau of Land Management to prepare an environmental statement which, in general, will describe the following topics: The proposed leasing action; the management system pertaining to the proposed action, including leasing procedures, supervision, inspection, and regulation of lease operations, and monitoring of actual and threatened environmental effects of lease operations; OCS oil and gas resource potential; energy supply and demand; technology for developing oil and gas offshore; environmental settings; natural phenomena that exist or occur in particular OCS regions, and which have the potential to cause or contribute to environmental impacts arising from the proposed action; the potential environmental impacts of the proposed action, offshore and onshore, including without limitation matters such as the cumulative impact of oil and gas operations under the proposed leasing action, impacts on competing uses of OCS resources, the effect of the proposed action on the level of environmental study prior to leasing and on the level of supervision of lease operations after leasing, and the degree to which environmental effects might be reduced as a result of improvements in methods of lease supervision; and the alternatives to the proposed action and their potential environmental impacts.

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[1] The line drawn from a point at: 42°19.9′ N. latitude, 67°46.9′ W. longitude, thence to 42°9.3′ N. latitude, 67°40.0′ W. longitude, thence 41°42.4′ N. latitude, 67°28.8′ W. longitude, and ending at 41°15.3′ N. latitude, 66°58.9′ W. longitude.

In due course, the Bureau of Land Management will prepare and disseminate a draft environmental statement and solicit comments on the statement from other Federal agencies, State and local governments, and interested members of the public. Moreover, it is the intention of the Bureau of Land Management to schedule public hearings, the location of which will be designated in a future notice published in the FEDERAL REGISTER, to consider the proposed action and the draft environmental statement.

The Bureau of Land Management will prepare individual environmental statements pursuant to section 102(2)(C) of the National Environmental Policy Act, supra, for each potential lease sale involved in the proposed action. This will provide a detailed environmental analysis on a tract-by-tract basis.[2]

The reasoning behind the proposed program and the determination to prepare a formal assessment of the environmental impacts of the proposal to increase OCS oil and gas leasing is as follows:

(a) Energy consumption in the United States will continue to rise. Despite conservation measures which have been instituted as a result of the recent oil embargo, all predictions indicate that there will be further increases in demand. Should domestic oil production continue to decline and demand continue to grow as in the past, imports would necessarily increase from 35 percent of U.S. consumption in 1973 to roughly half of U.S. consumption by 1980.

(b) The substantial rise in foreign oil prices in recent months also has created difficulties. If foreign oil purchases are increased, there would be a chronic balance of payments outflow which would create critical problems in international monetary affairs.

(c) An increase in domestic oil and gas production offers the greatest chance among available alternatives of avoiding increasing dependence upon potentially insecure foreign supplies of energy. While the mix between energy forms may change somewhat with rapid growth of other forms of energy such as increases in coal production and development of nuclear energy, the U.S. must continue to be heavily dependent on oil and gas through the next two decades.

(d) The Outer Continental Shelf represents a large and promising area for oil and gas exploration. The Department's Geological Survey estimates undiscovered recoverable oil resources offshore totalling 65 to 130 billion barrels of petroleum (7-14 State and 58-116 Federal) and 395 to 790 trillion cubic feet of gas (40-80 State and 355-710 Federal). Production from those resources, in addition to production from known OCS resources, would greatly help in attaining the goal of avoiding dependence on insecure foreign sources of oil and gas.

(e) The proposed action to increase OCS oil and gas leasing to 10 million acres in 1975 is a major Federal action significantly affecting the quality of the human environment.

(f) The environmental statement process articulated in the National Environmental Policy Act provides a formalized method for evaluating the environmental impact of OCS development. For example, the view—that the considerable OCS development which has occurred to date has not resulted in long lasting, unacceptable marine or shoreside environmental or socio-economic impacts—would be evaluated.

The viability of the program, and the bases therefor, will be evaluated in the decision-making processes of which the environmental statement concerning the increases in OCS leasing from approximately 3 million acres in 1974 to 10 million acres in 1975, and the individual environmental statements on the 1975 sales, are a part. Studies and views that will be considered in these decision-making processes include more than the preparation of the environmental statements referred to. The following steps have already been taken:

(a) On April 18, 1973, the President directed the Council on Environmental Quality to study the potential environmental impacts of OCS oil and gas exploration and development along the Atlantic Coast and the Gulf of Alaska. The Report of the Council on Environmental Quality, OCS Oil and Gas—An Environmental Assessment, which was submitted to the President on April 18, 1974, is undergoing a thorough review within the Department.

(b) On February 20, 1974, the Bureau of Land Management published in the FEDERAL REGISTER (39 FR 6541), a "Request for Comments" inviting and encouraging all concerned parties representing the oil and gas industry and the general public to submit information concerning areas of interest for oil and gas resource potential and areas of environmental concern. Comments received to date in response to this request are now being studied and analyzed within the Department of the Interior, and a report will be released in the near future. This is one action taken during the first tier of a new two-tier system for selecting potential OCS leasing areas and individual tracts within those areas. The Bureau of Land Management will use these rankings of areas, and its own evaluations of resource potential and need to protect environmental values, the CEQ report, and views of other Federal agencies to identify areas for
tial lease sales. In the second tier
system, industry and other group
be asked to provide their views
dividual tracts within areas as i
past. Thereafter, an environn
statement for the individual leas
would be prepared, as mentioned
and if the sale is determined to b
vironmentally acceptable, the ter
the leases would be established, ar
sale held.

(c) The Department is conducti
inventory and analysis of existin
vironmental and socio-economic
The CEQ report represents a signi
contribution to this level of effort.
tracts have been entered into witl
versities for more specific analy
frontier areas such as the North At
from the Bay of Fundy to Sandy
New Jersey; the mid-Atlantic,
Sandy Hook to Cape Hatteras; the
Atlantic, from Cape Hatteras to
Canaveral; and the Gulf of Alaska
Cook Inlet to Unimak Island. Th
partment has also contracted for s
of southern California and is broad
and updating our information co
ing the Gulf of Mexico.

(d) The Secretary of the Interi
created a Federal-State Researc
visory Board which will advise o
scope and conduct of baseline studi
monitoring programs for potential
ing in frontier areas of the Atlant
Alaska. We expect to issue a num
contracts for base-line studies aft
ceiving advice from the advisory
Representatives of seaboard States
been invited to participate on the
and others will be so invited.

In this connection, the Depar
has decided to proceed in nearly
taneous time frames with environn
base-line studies on the Outer
nental Shelves of the Atlantic Ocea
the Gulf of Alaska in order to e
further the feasibility of oil and ga
ing in those areas. These base-line s
will consider weather, sea state, bi
populations and natural hazards.
design will draw upon the Na
Oceanic and Atmospheric Administ
(NOAA), Bureaus in the Departme
States, and the private sector. NOA
the USGS have been asked to desi
propriate studies for the Gulf of
for early consideration by the Ad
Board. Because legal issues may
OCS development in the Atlanti
Gulf of Alaska may be the first fr
area in which an OCS sale could b

The Gulf of Alaska was identif
the CEQ in its recent report as
the frontier OCS areas with the gr
environmental risk. The studies
undertaken are necessary to dete
the acceptability of leasing in this
The Department believes steps s
now be taken to protect the optio
sale in that area near the end o
if the difficult environmental and
nological problems identified in th
report can be satisfactorily dealt
The Department has no intention o
ing anywhere on the OCS if it can

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[2] Decisions to prepare environmental impact statements for potential lease sales would take into account the status of pending litigation, including U.S. v. Maine et al. and U.S. v. Florida.

plished in an environmentally ac-
le way.

The Department is now evaluating
sibility of requiring permittees and
to furnish the Secretary with
of all data obtained during off-
exploration and development for
l gas. Notice of proposed rule mak-
ill be published in the FEDERAL
TER for public comment soon.

Officials of the Department of the
or have been involved in a continu-
alogue with environmental organi-
s, representatives of industry and
concerned individuals in an effort
ain the benefit of their views rela-
the environmental aspects and the
d gas potential of the proposed ac-
Discussions have been held on the
bility of an OCS exploratory pro-
that would further help to pinpoint
eas of the greatest potential pro-
n of oil and gas. These discussions
involved a number of alternative
which include: special limited lease
n frontier areas with a requirement
ompt exploration; leases for ex-
ion only; a Federal exploratory
g program; and off-structure
graphic drilling by both private
ublic entities.

sons wishing to express their views
rning the preparation of an en-
nental impact statement for the
sed program to increase OCS oil
as leasing and the other undertak-
eferred to may submit comments to
tor, Attention 730, Bureau of Land
gement, Washington, D.C. 20240.

GEORGE C. TURCOTT,
Associate Director,
Bureau of Land Management.

proved: May 13, 1974.

OHN C. WHITAKER,
Under Secretary of the Interior.

Doc.74-11447 Filed 5-17-74;8:45 am]

Office of Hearings and Appeals

[Docket No. M74-113]

IMBO COAL COMPANY, INC.

on for Modification of Application of Mandatory Safety Standard

ice is hereby given that in accord-
with the provisions of section 301(c)
e Federal Coal Mine Health and
y Act of 1969, 30 U.S.C. 861(c)
, Bimbo Coal Company, Inc. has
a petition to modify the application
CFR 77.1605(k) to its No. 2 Mine
d at Hall Hollow, Buchanan
ty, Virginia.

CFR 77.1605(k) provides as follows:

> ms or guards shall be provided on the
> bank of the elevated roadways.

e alternate method which Petitioner
oses to establish in lieu of the man-
y standard is as follows:

> A daily inspection of all coal-hauling
> les shall be made and any defects de-
> shall be corrected before the vehicle
> into service. A record of the inspection and repair on each vehicle shall be kept and maintained by a supervisory employee.
>
> 2. Roadway surfaces shall be kept free of debris, excessive water and snow and ice, and maintained as free as practicable of small ditches (washboard effects).
> 3. A traffic system should be put into use for these roads requiring that the loaded vehicles have the right-of-way on the highwall side of roads regardless of their direction of travel.
> 4. Warning signals shall be posted designated curves, steep grades where trucks should shift to a lower gear, and where roadways are reduced to one-lane traffic. Stop signs shall be posted where one road intersects another, giving main haulage road traffic the right-of-way. Signs should also be posted designating passing points.
> 5. All equipment operators should be trained in the use of haulage equipment and the safety of vehicles on haulage roads.
> 6. All haulage vehicles shall have:
>
> (a) Original manufacturers brakes.
>
> (b) Engine or Jacobs brakes.
>
> (c) Emergency (parking) braking system.
>
> 7. Adequate supplies of crushed stone or other suitable materials shall be stored at strategic locations along the haulage roads for use when the road surface becomes slippery.
> 8. A minimum width of 30 feet shall be provided and maintained along two-lane roads, and where widths of less than 30 feet are provided and maintained, the roads shall be designated as single-lane roads.
> 9. On roads that afford only one traffic lane, a minimum width of 16 feet shall be maintained, with passing points provided at intervals of not more than 1,000 feet; if visibility is obscured by brush or other materials, passing points shall not be more than 500 feet apart.
> 10. Where abrupt drop-offs are present along the outer banks, super-elevation shall be provided to cause the vehicles to gravitate toward the highwall side of the road.
> 11. All rules of the road (traffic system) shall be posted on the bulletin boards throughout the mine area, and such rules of the road shall be made part of the training and retraining programs.

Petitioner further states that the alternative method outlined above will, at all times guarantee no less than the same measure of protection afforded the miners at the Petitioner's mine by the mandatory standard.

Persons interested in this petition may request a hearing on the petition or furnish comments on or before June 19, 1974. Such requests or comments must be filed with the Office of Hearings and Appeals, Hearings Division, U.S. Department of the Interior, 4015 Wilson Boulevard, Arlington, Virginia 22203. Copies of the petition are available for inspection at that address.

JAMES R. RICHARDS,
Director,
Office of Hearings and Appeals.

MAY 13, 1974.

[FR Doc.74-11463 Filed 5-17-74;8:45 am]

[Docket No. M 74-101]

O. C. COAL MINE #2

Petition for Modification of Application of Mandatory Safety Standard

Notice is hereby given that in accordance with the provisions of section 301(c) of the Federal Coal Mine Health and Safety Act of 1969, 30 U.S.C. 861(c) (1970), H. W. Weaver, d.b.a. O. C. Coal Mine #2 has filed a petition to modify the application of 30 CFR 75.1405 to its O. C. Coal Mine #2 located at Gunnison, Colorado.

30 CFR 75.1405 provides as follows:

> All haulage equipment acquired by an operator of a coal mine on or after March 30, 1971, shall be equipped with automatic couplers which couple by impact and uncouple without the necessity of persons going between the ends of such equipment. All haulage equipment without automatic couplers in use in a mine on March 30, 1970, shall also be so equipped within 4 years after March 30, 1970.

Petitioner seeks a waiver of the foregoing safety standard for the following reasons:

(1) Petitioner utilizes forty inch wide, one-ton wooden cars in its mine. These cars comprise two three-car trips which are hauled by one-half inch rope cable. The cars are manuevered by hand on the surface, and they are pulled inside by a mule.

(2) The subject cars are not uncoupled in the mine. The uncoupling takes place aboveground on a flat surface when the cars are at rest.

(3) The size and awkwardness of automatic couplers would create a safety hazard. In addition, the installation of said couplers would prove impractical because:

(a) The cars are too small to accommodate the couplers.

(b) Petitioner's personnel would be unable to manuever the cars by hand on the surface.

(c) It would not be possible to manuever the cars underground by mule.

(d) The mine will continue to produce coal for only three more years.

(4) The alternate method will at all times guarantee no less than the same measure of protection as afforded by the application of the mandatory standard.

Persons interested in this petition may request a hearing on the petition or furnish comments on or before June 19, 1974. Such requests or comments must be filed with the Office of Hearings and Appeals, Hearings Division, U.S. Department of the Interior, 4015 Wilson Boulevard, Arlington, Virginia 22203. Copies of the petition are available for inspection at that address.

JAMES R. RICHARDS,
Director, Office of
Hearings and Appeals.

MAY 13, 1974.

[FR Doc.74-11466 Filed 5-17-74;8:45 am]

[Docket No. M 74-102]

O. C. COAL MINE #2

Petition for Modification of Application of Mandatory Safety Standard

Notice is hereby given that in accordance with the provisions of section 301(c) of the Federal Coal Mine Health and Safety Act of 1969, 30 U.S.C. 861(c) (1970), H. L. Weaver, d.b.a. O. C. Coal Mine #2 has filed a petition to modify the application of 30 CFR 75.313 to its O. C. Coal Mine #2 located in Gunnison, Colorado.

30 CFR 75.313 provides in pertinent part as follows:

ATTACHMENT F

UNITED STATES
DEPARTMENT OF THE INTERIOR
Bureau of Land Management

OUTER CONTINENTAL SHELF RESEARCH ADVISORY BOARD

Establishment and Functions

This notice is issued in accordance with the provisions of 5 U.S.C. 552(a)(1), and section 9(a)(2) of the Federal Advisory Committee Act (Public Law 92-463). The Secretary of the Interior has established an Outer Continental Shelf Research Advisory Board after consultation with the Office of Management and Budget, in accordance with the provisions of the Federal Advisory Committee Act (Public Law 92-463). The Office of Management and Budget Committee Management Secretariat has authorized a 7-day period in lieu of the required 30-day period between Federal Register publication of the Board charter, and its filing as prescribed in Section 9(c) of Public Law 92-463. This Board will advise the Assistant Secretary - Land and Water Resources, the Director of the Bureau of Land Management, and other Departmental officers in matters related to environmental baseline and monitoring studies on the Federal Outer Continental Shelf lands. The Board charter is published in its entirety below. Further information regarding this document may be obtained from Mr. Frederick N. Ferguson, Assistant Solicitor - Minerals, Office of the Solicitor, U.S. Department of the Interior, Washington, D.C. 20240, telephone (202) 343-4325.

SIGNED, JOHN C. WHITAKER

Under Secretary of the Interior

Date: MAR 20 1974

CHARTER

OUTER CONTINENTAL SHELF RESEARCH MANAGEMENT ADVISORY BOARD

1. There is hereby established, pursuant to the provisions of the Federal Advisory Committee Act (5 U.S.C. 1970 ed., Supp. II, App. I), an Outer Continental Shelf Research Management Advisory Board. The Board will advise officers of the Department in the performance of discretionary functions of the Department under the Outer Continental Shelf Lands Act (43 U.S.C. §§ 1331-1343) in connection with baseline environmental data gathering and environmental monitoring on the Outer Continental Shelf (OCS). The functions of the Board are solely advisory.

2. The objective of the Board is to advise the Assistant Secretary-Land and Water Resources, the Director, Bureau of Land Management (BLM) and other officers of the Department, in the design and implementation of environmental research projects related to oil and gas exploration and development on the OCS. The objectives of the OCS program are: (1) orderly resource development, (2) protection of the environment, and (3) receipt of fair market value. This Board through its advisory efforts will assist the Bureau in meeting objectives (1) and (2). In order to fully realize its potential, it is anticipated that the Board will be required for the duration of OCS environmental baseline research and monitoring studies, a period of approximately ten years. The Board will, however, terminate on December 31, 1975, unless prior

to that date it is renewed for an additional period by the Secretary of the Interior, acting within his discretion and in accordance with the provisions of section 14(a)(2) of the Federal Advisory Committee Act, supra.

3. The Board will report directly to the Assistant Secretary-Land and Water Resources. (a) The Assistant Secretary-Land and Water Resources shall, after consultation with the Assistant Secretary-Energy and Minerals and the Assistant Secretary for Fish, Wildlife and Parks, appoint an employee of the Department of the Interior as Chairman for the Board. The Assistant Secretary-Land and Water Resources shall be responsible for assuring that the Board operates within statutory and Departmental requirements for the management of advisory committees. The Director, BLM, shall provide administrative support. (b) Each of the following Departmental bureaus shall appoint one member to the Board: the Geological Survey, and the Bureau of Sport Fisheries and Wildlife. The Administrator of the Environmental Protection Agency and the Administrator of the National Oceanic and Atmospheric Administration may each appoint one member. (c) At the invitation of the Secretary of the Interior, the Governor of each State off the coast of which OCS research projects are scheduled may nominate for appointment by the Secretary one member who shall represent that State on the Board. Initially the Governors of Mississippi, Alabama, and Florida will be asked to nominate Board

members. As OCS research projects expand into other geographic areas the Governors of the respective States involved may be invited to nominate members for appointment to the Board. (d) Each Federal member shall serve until his resignation, the termination of the Board, or his removal by the officer appointing him. If the agency appointing a member removes that member, it may appoint another in his place. Each non-Federal member shall be appointed to serve a one-year term, but may be re-appointed for additional one-year periods if the OCS area seaward of his State is still under active research.

4. (a) Subject to the limitations imposed by this Charter, the Board may establish its own procedures for the conduct of business. To facilitate the performance of the Board's functions, the Chairman may establish committees composed of members of the Board. Most scheduled meetings will be of specific committees, but the Chairman will have the latitude to invite any individual State member to any committee meeting. (b) The Board shall prepare an annual report to the Secretary on the status of ongoing environmental OCS research. This report will be made available to the public.

5. The Chief Scientist for the BLM OCS environmental research program or a person designated by him will attend all Board and committee meetings and will assist the Chairman wherever possible.

6. The Board will meet at the call of the Chairman, who shall give at least fifteen day's notice in writing. The Board is expected to meet at least bi-annually. Meetings will be conducted in accordance with statutory and Departmental requirements for advisory committees as prescribed in 308 DM 2 of the Department of the Interior Manual. The estimated total annual operating costs of the Board are $10,000 and one man year of staff support.

7. The formation of this committee is determined to be in the public interest in connection with the performance of duties of this Department pursuant to statute as stated in paragraph 1 above. This Charter shall become effective April 1, 1974.

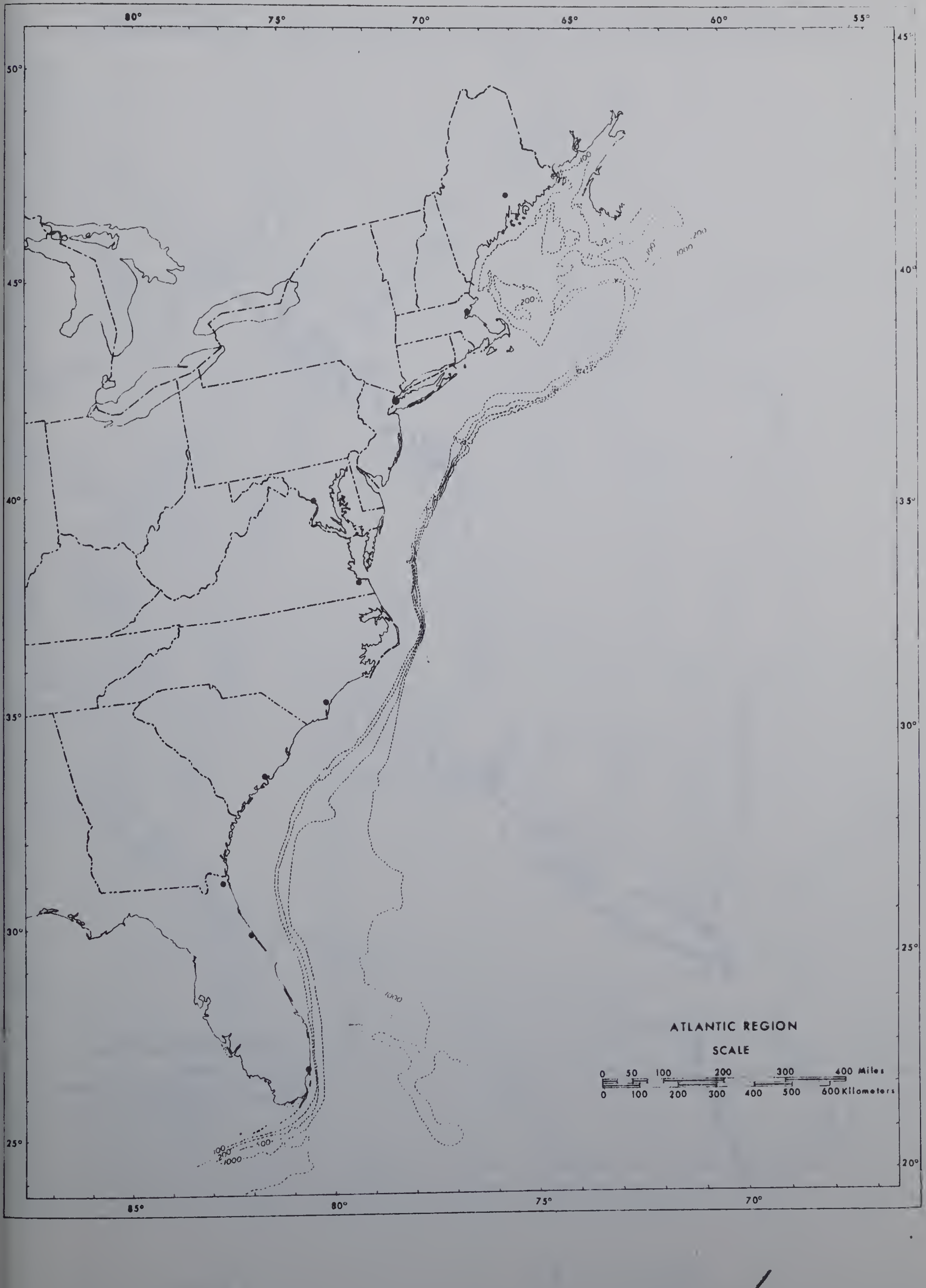
SIGNED, JOHN C. WHITAKER

Under Secretary of the Interior

Date: MAR 20 1974

ATTACHMENT G

613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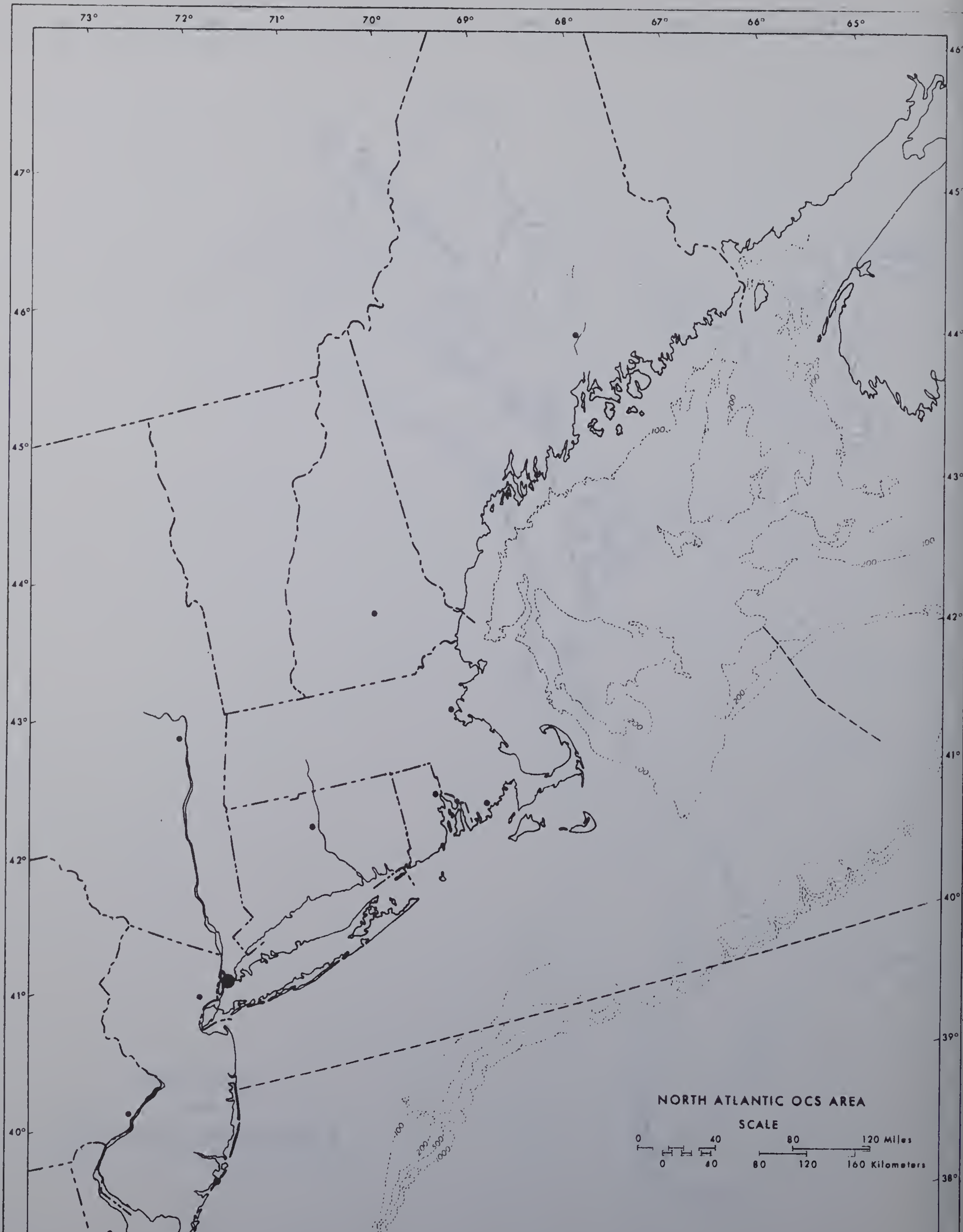
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1000

1

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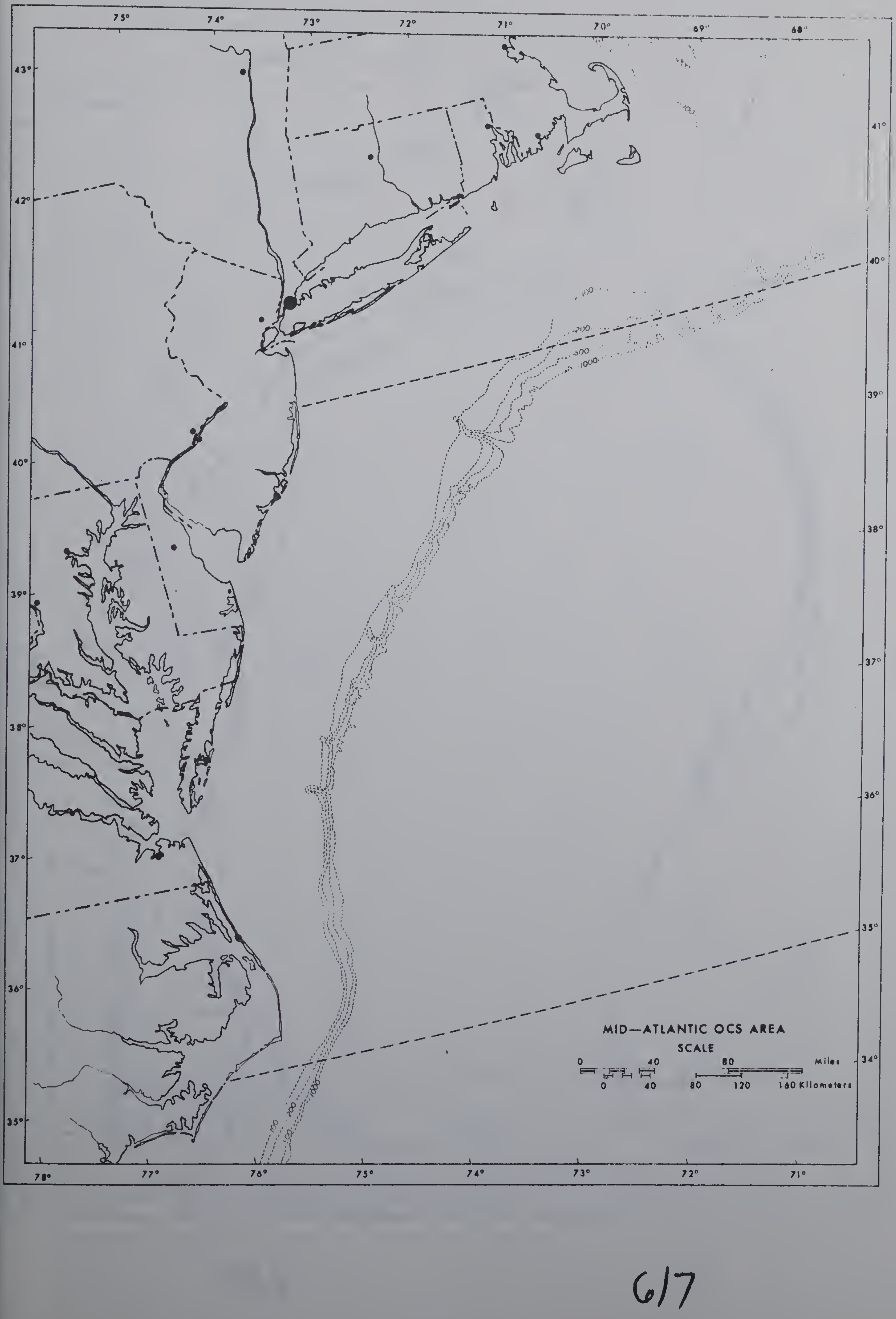
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43°
42°
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39°
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36°
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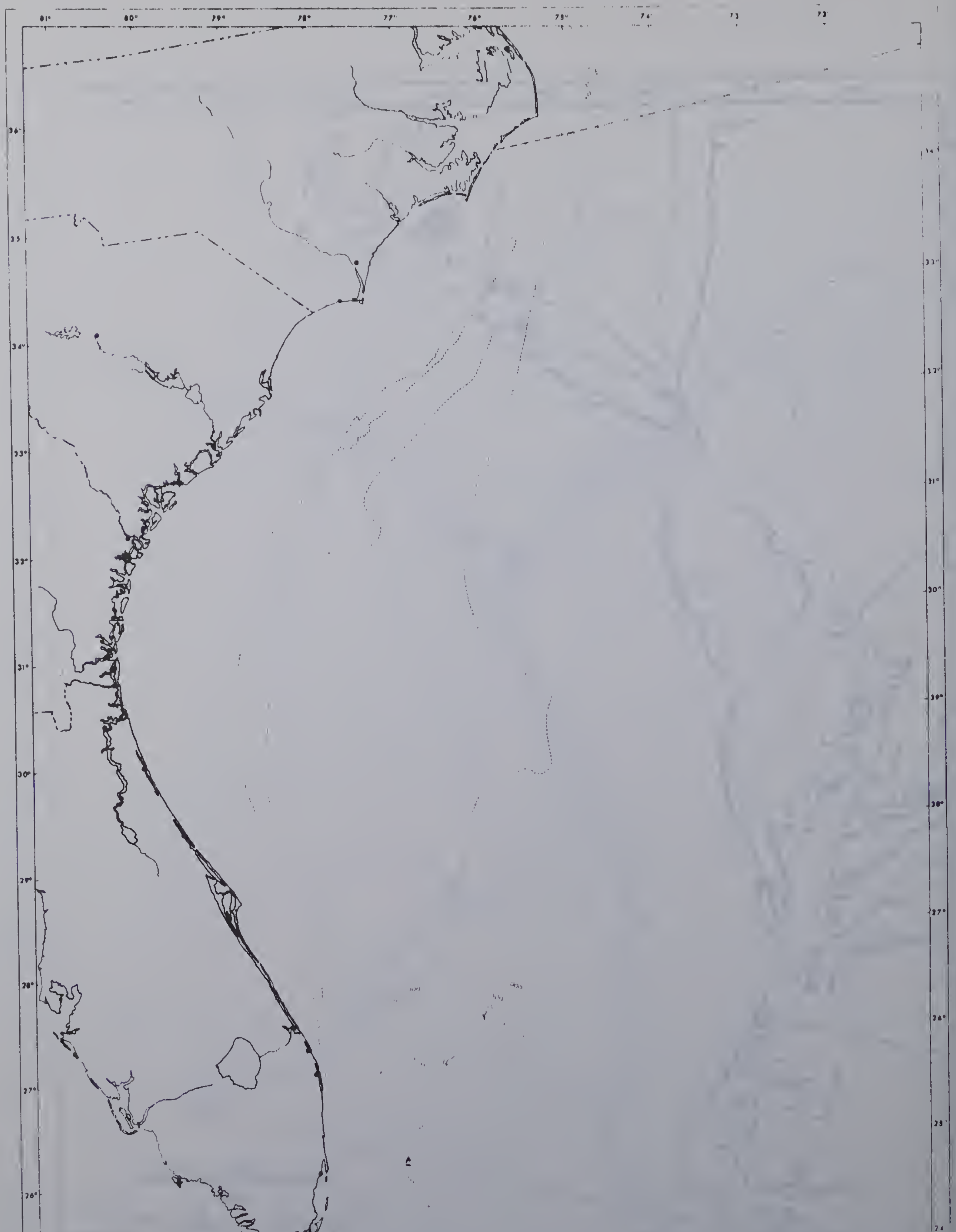
77°
76°
100
200
500
1000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81°
80°
79°
78°
77
76
75
34
33
32
31°
30°
29°
28°
27°
26°
25
24
23
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SCALE
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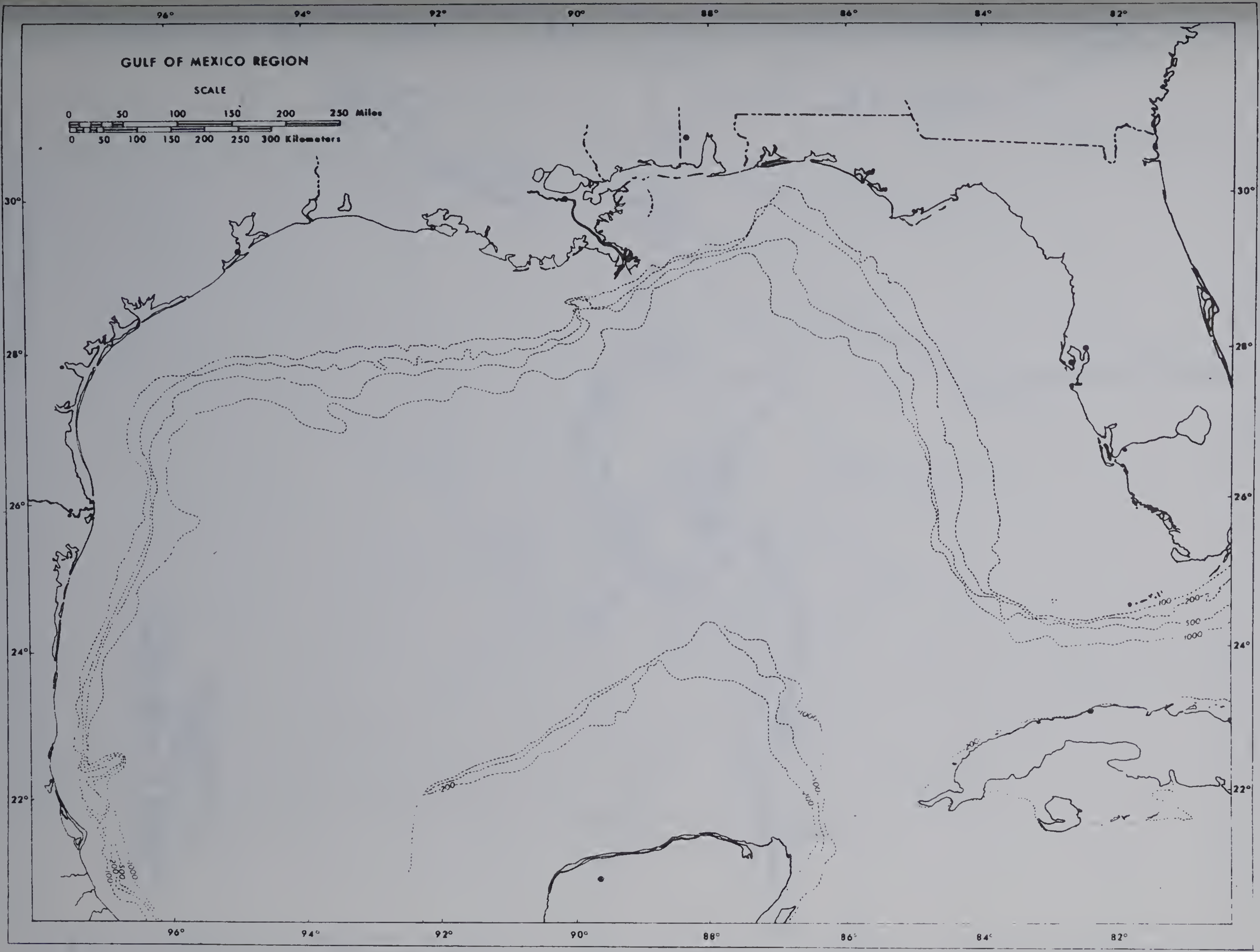
80
120
160 Kilometers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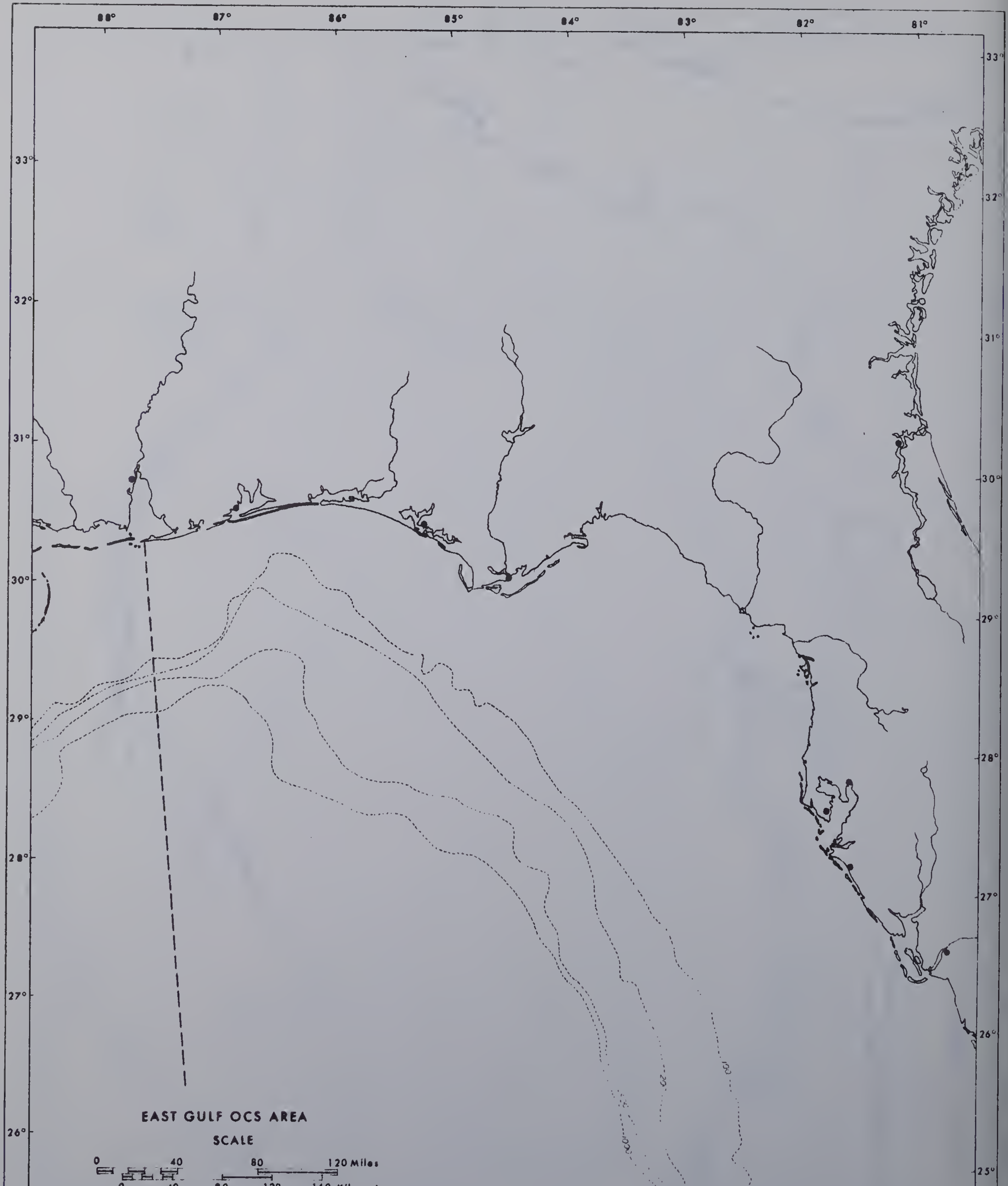
22°
100
200
500
1000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26°
25°
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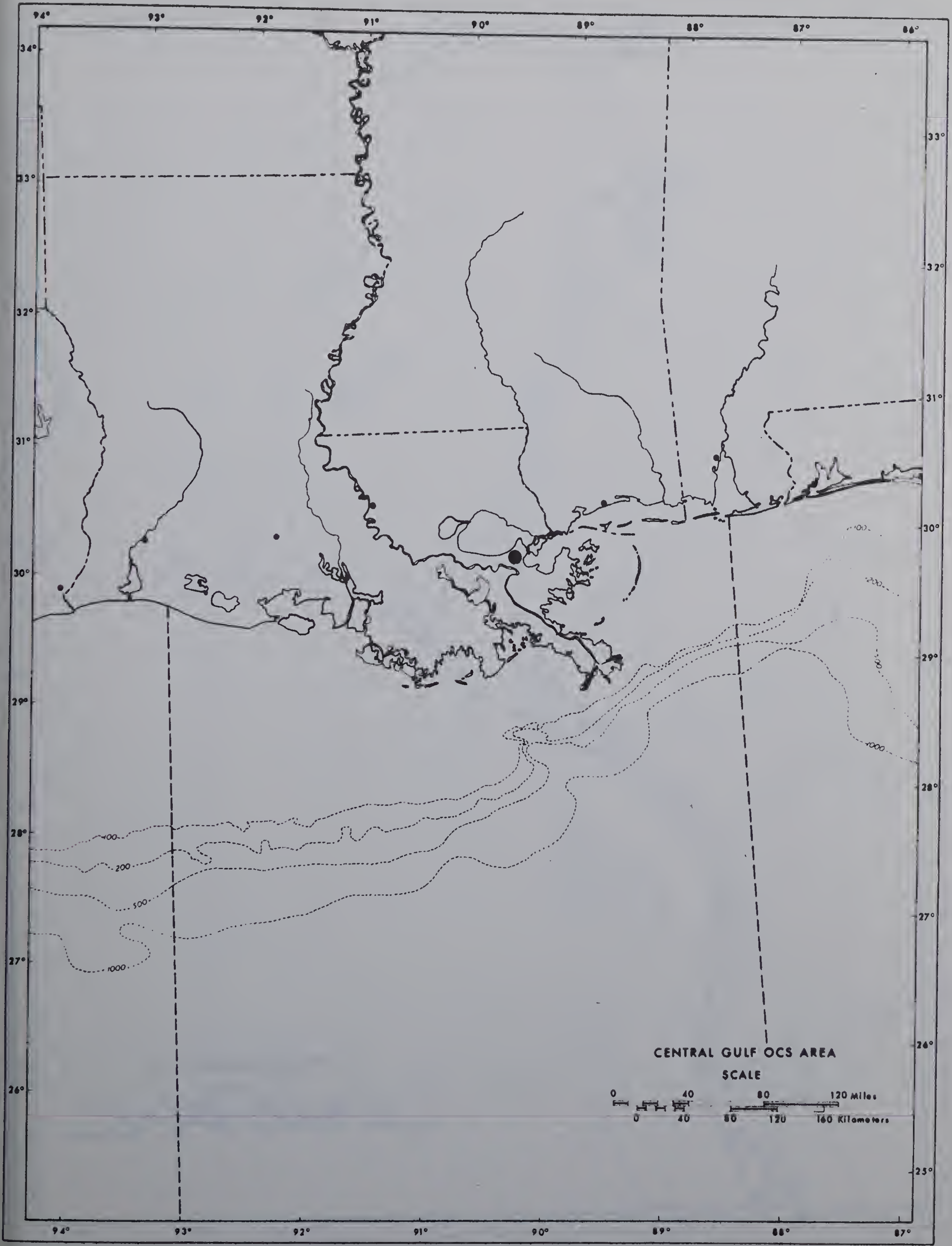
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SCALE
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100
200
500
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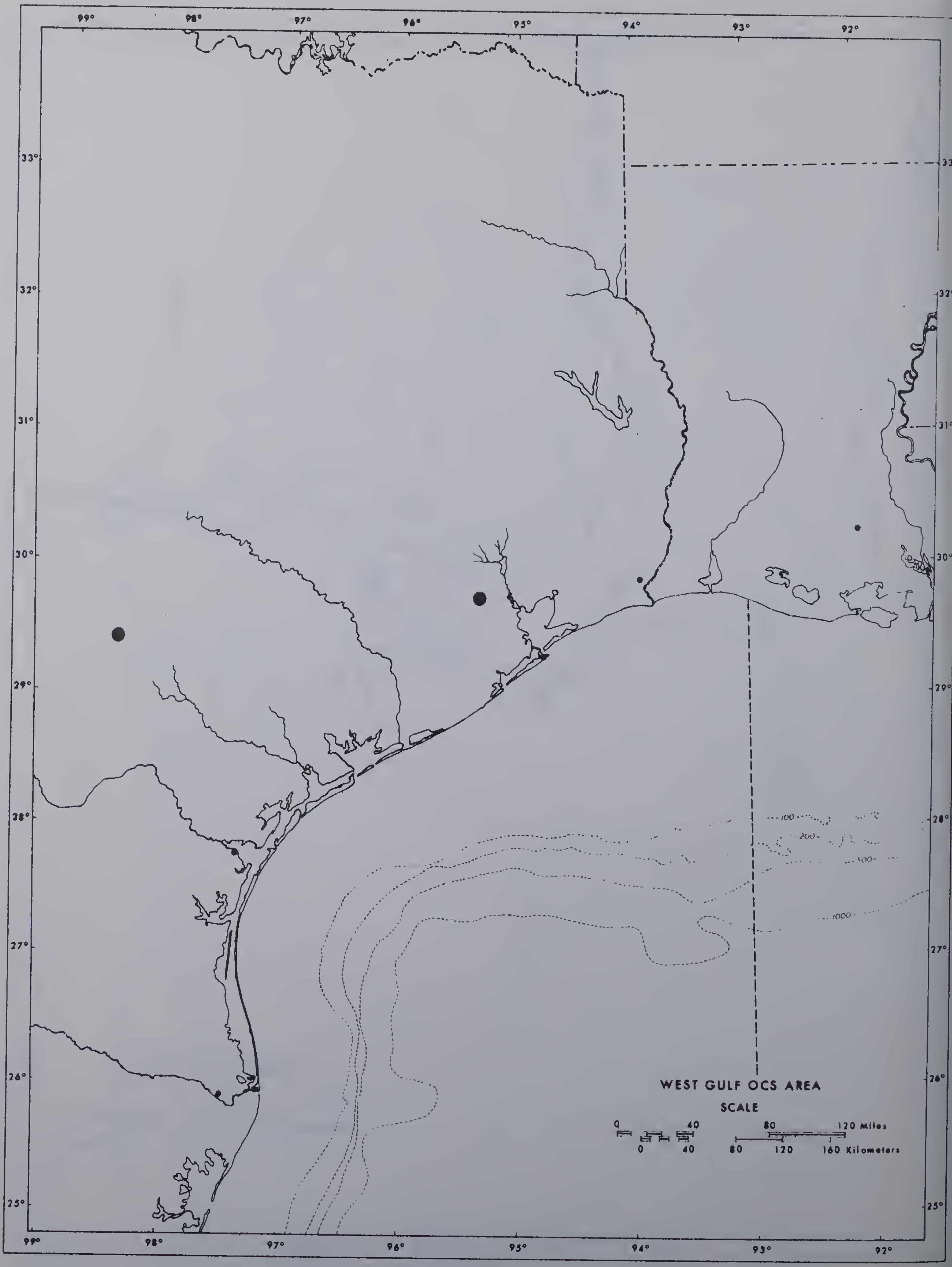
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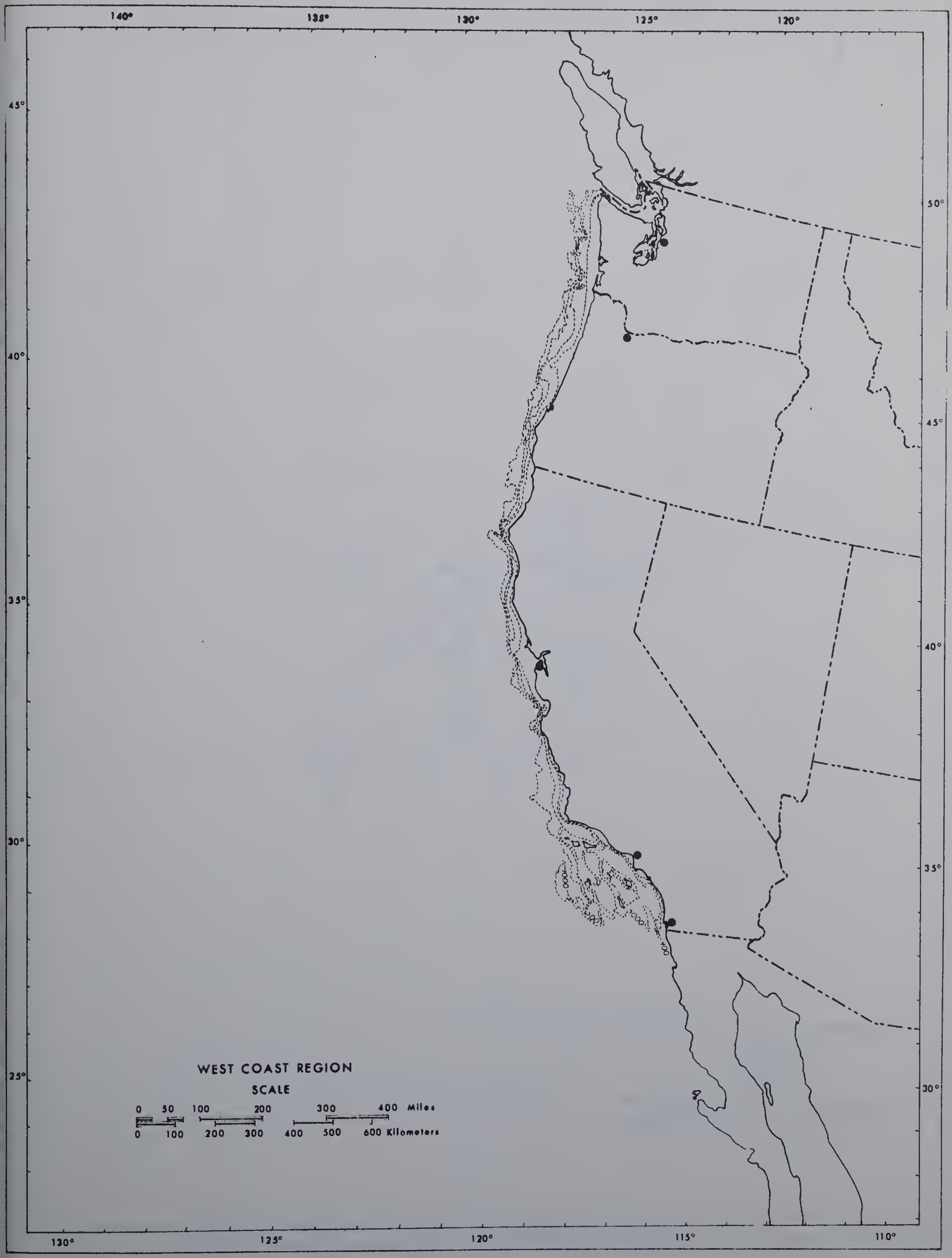
100
200
500
1000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SCALE
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30°
25°
50°
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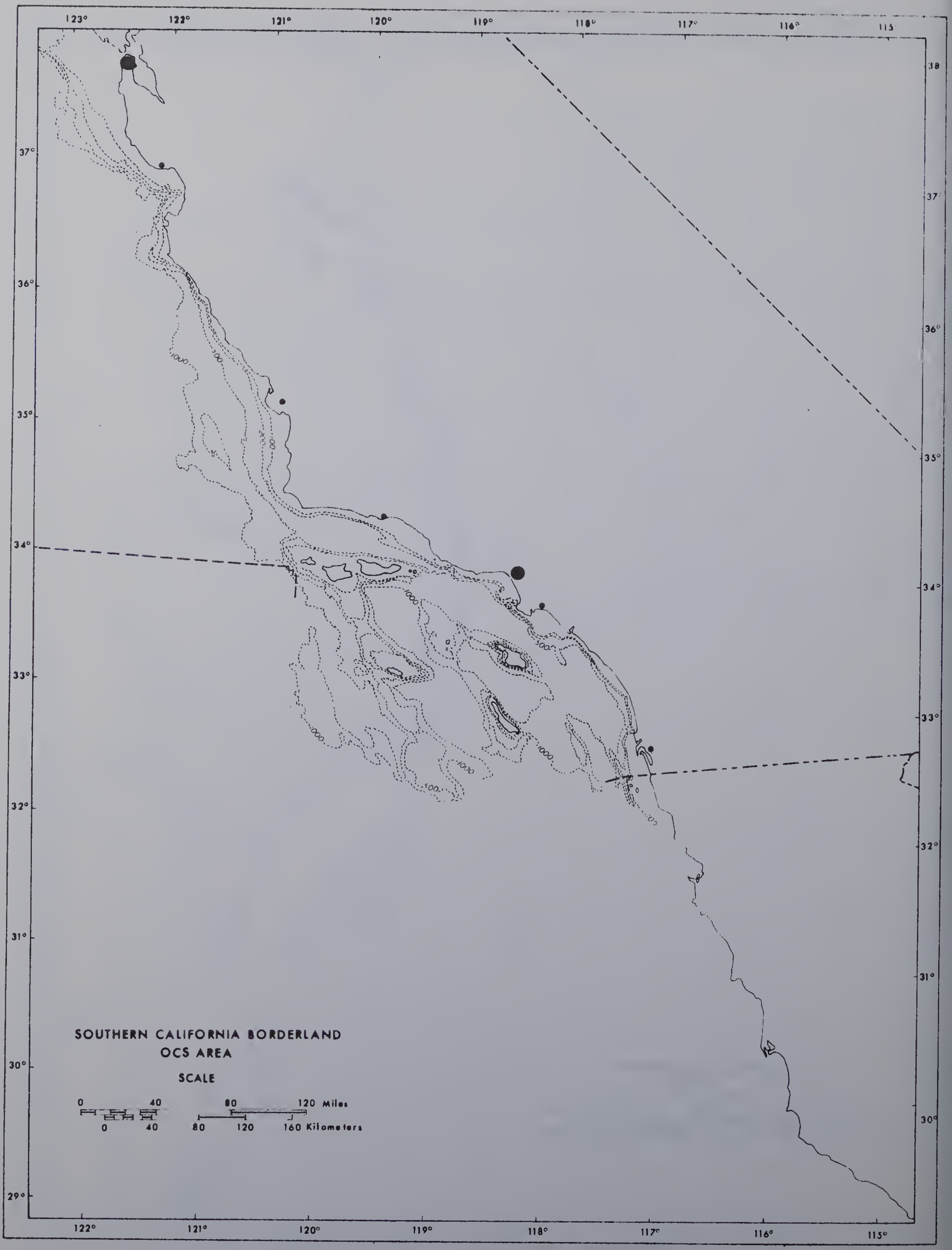
SOUTHERN CALIFORNIA BORDERLAND
OCS AREA
SCALE
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38° 37° 36° 35° 34° 33° 32° 31° 30° 29°
1000
100
500
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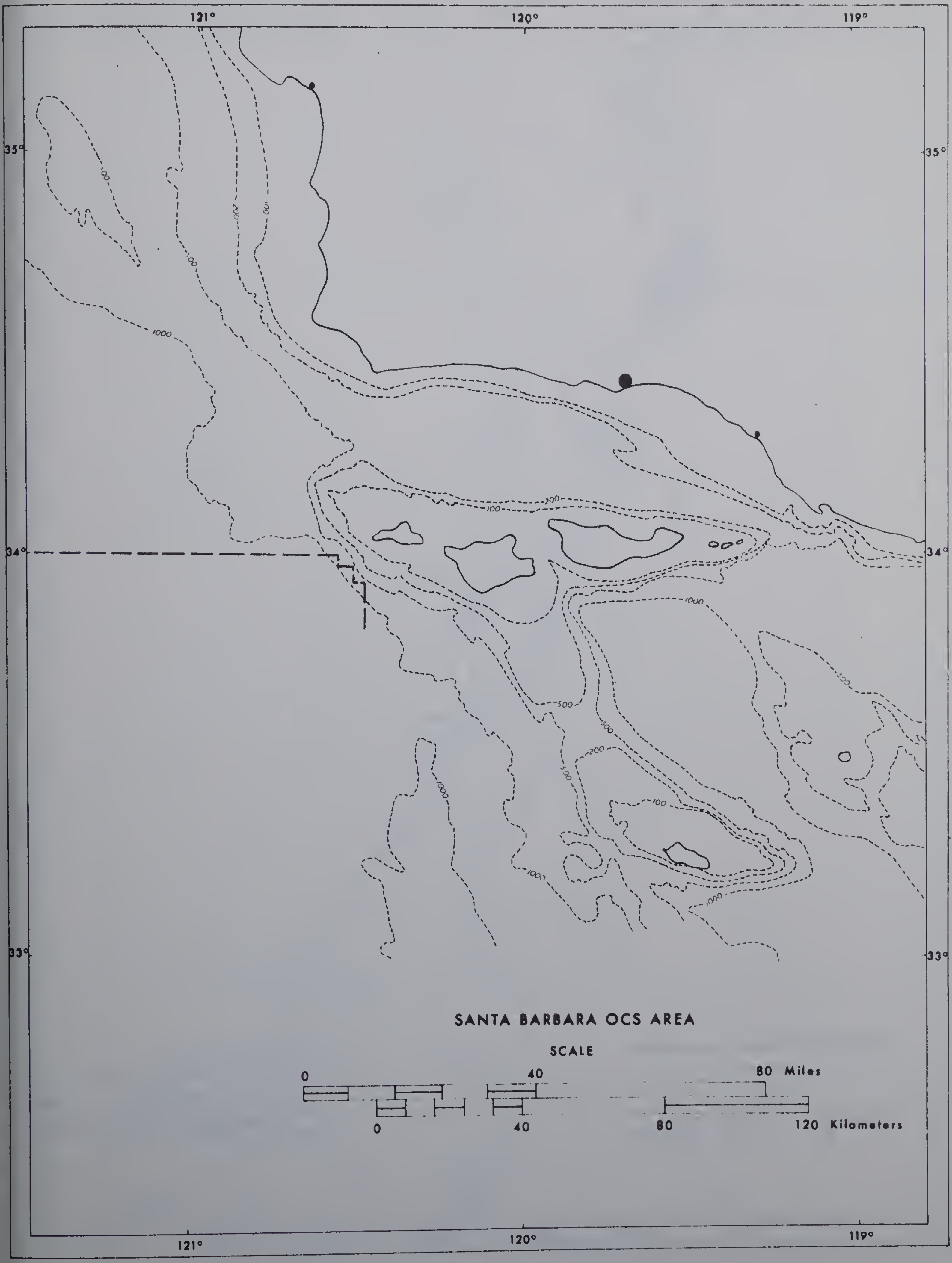
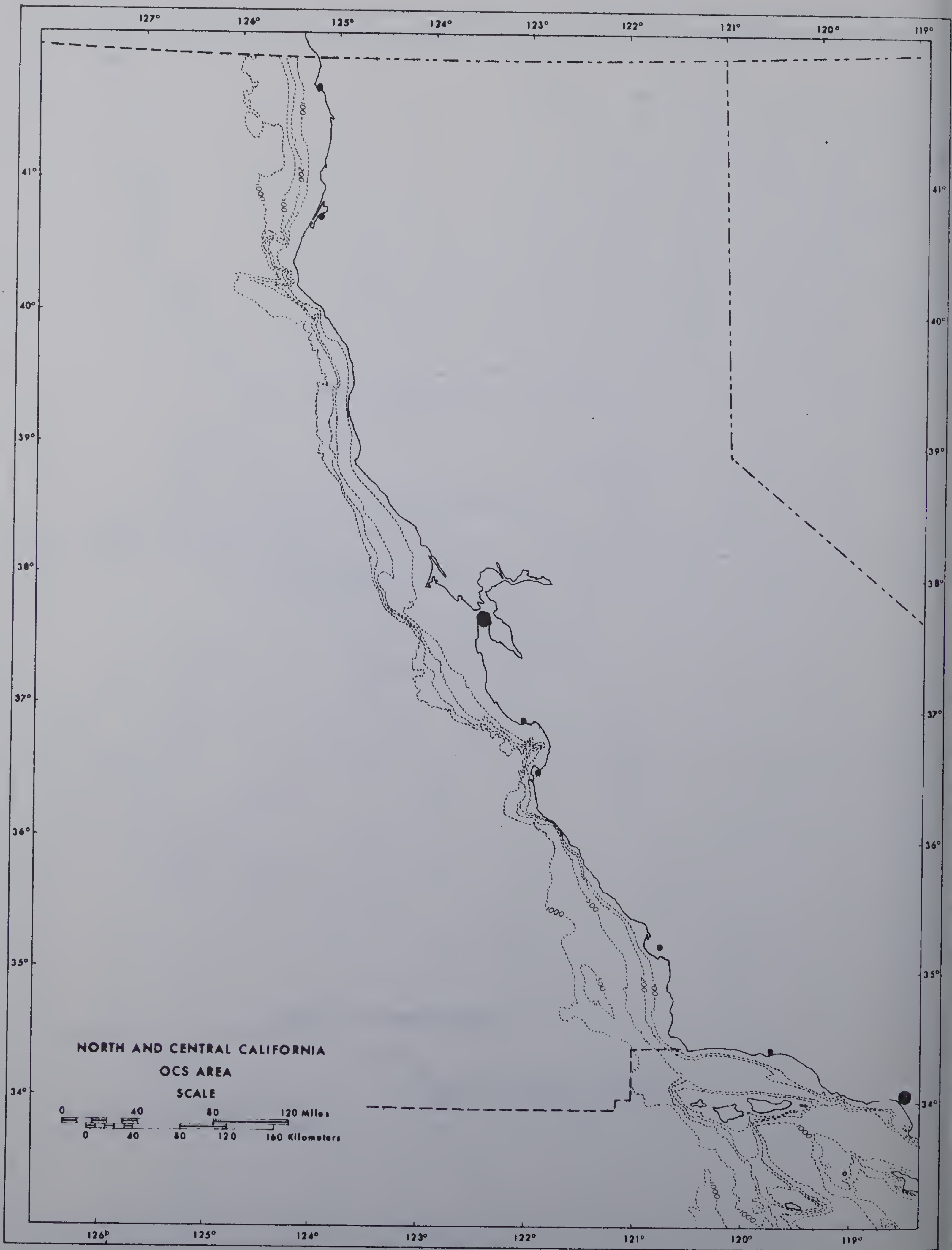
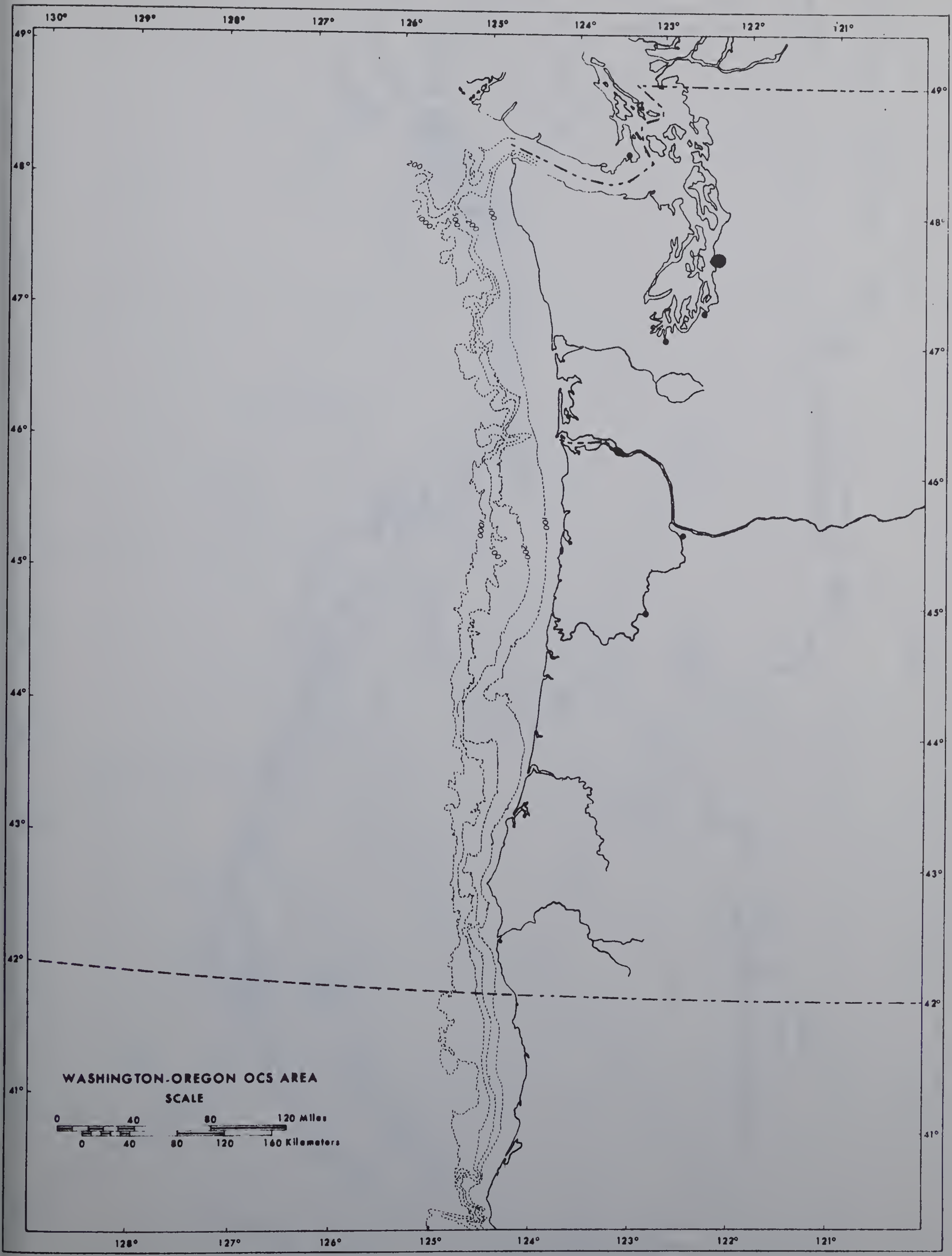


SANTA BARBARA OCS AREA

SCALE


NORTH AND CENTRAL CALIFORNIA OCS AREA


WASHINGTON-OREGON OCS AREA
SCALE
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200
1000
500
100

ALASKA
SCALE
0 100 200 300 400 500 Miles
0 200 400 600 800 Kilometers
148° 152° 156° 160° 164° 168° 172° 176° 180° 176° 172° 168° 164° 160° 156° 152° 148° 144° 140° 136° 132° 128° 124° 120° 116° 112°
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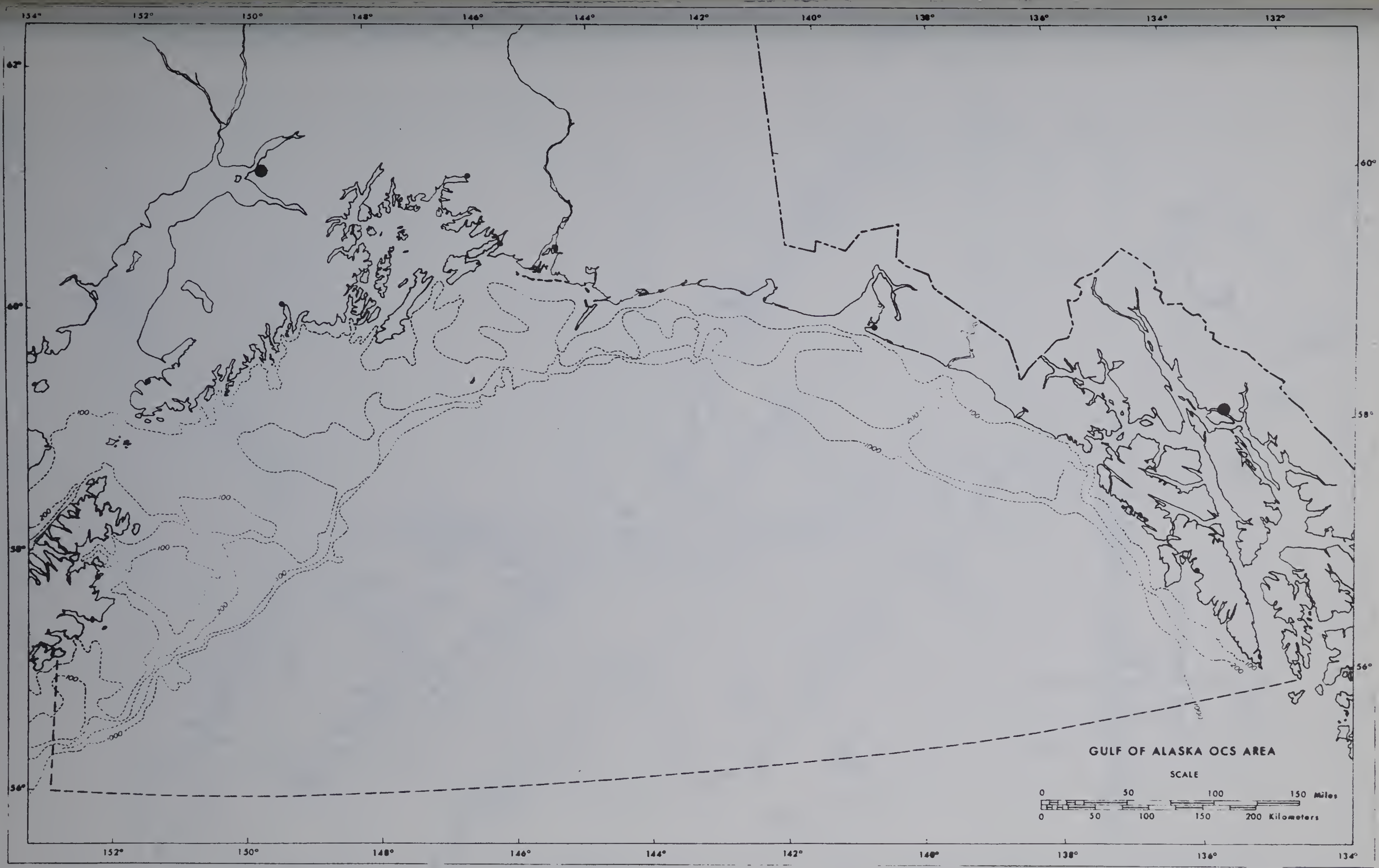
100
200
1000

628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150°
148°
146°
144°
142°
140°
138°
136°
134°
132°
62°
60°
58°
56°
100
200
1000
GULF OF ALASKA OCS AREA
SCALE
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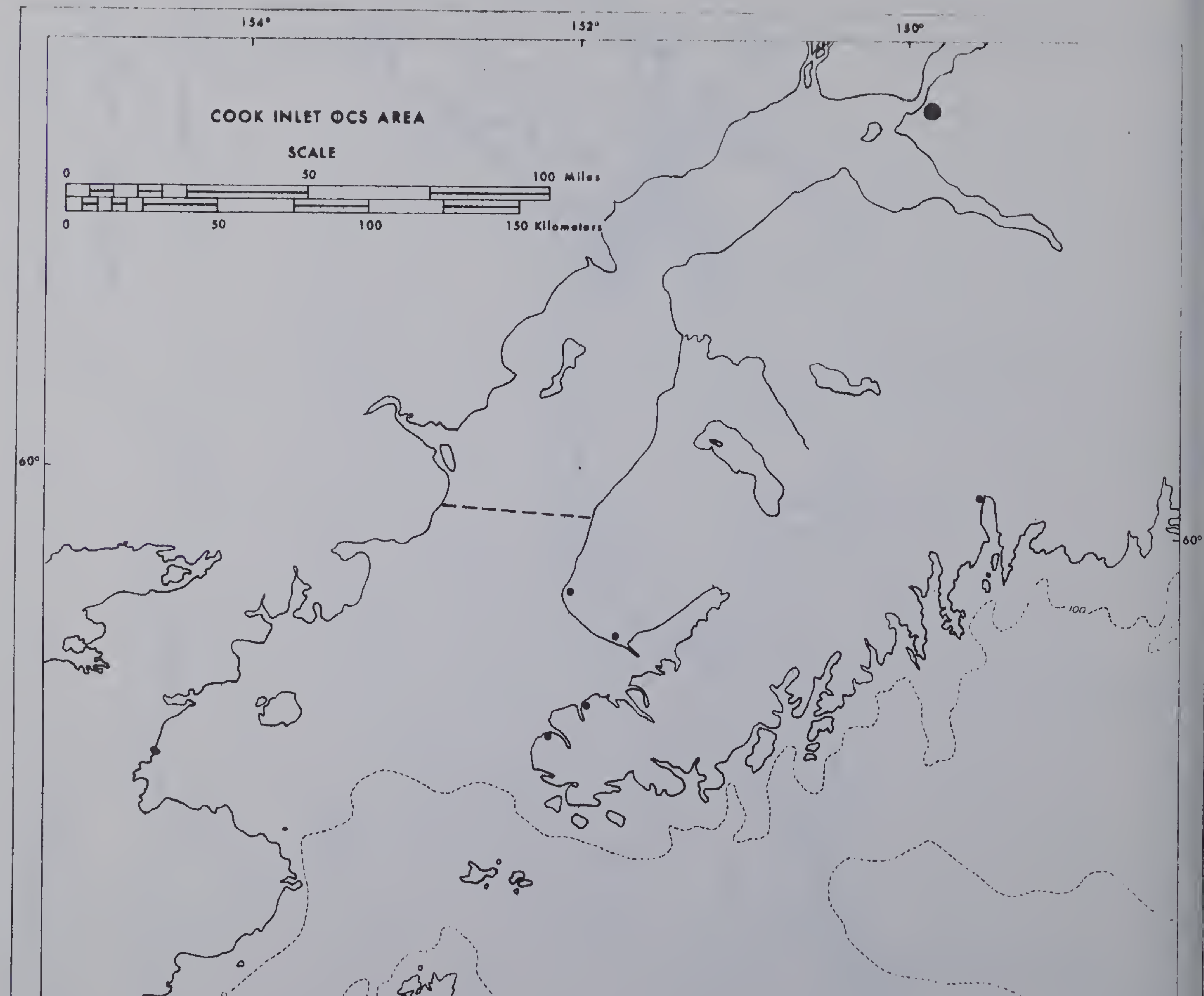
0 50 100 150 200 Kilometers


COOK INLET OCS AREA
SCALE
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100 Miles
0
50
100
150 Kilometers
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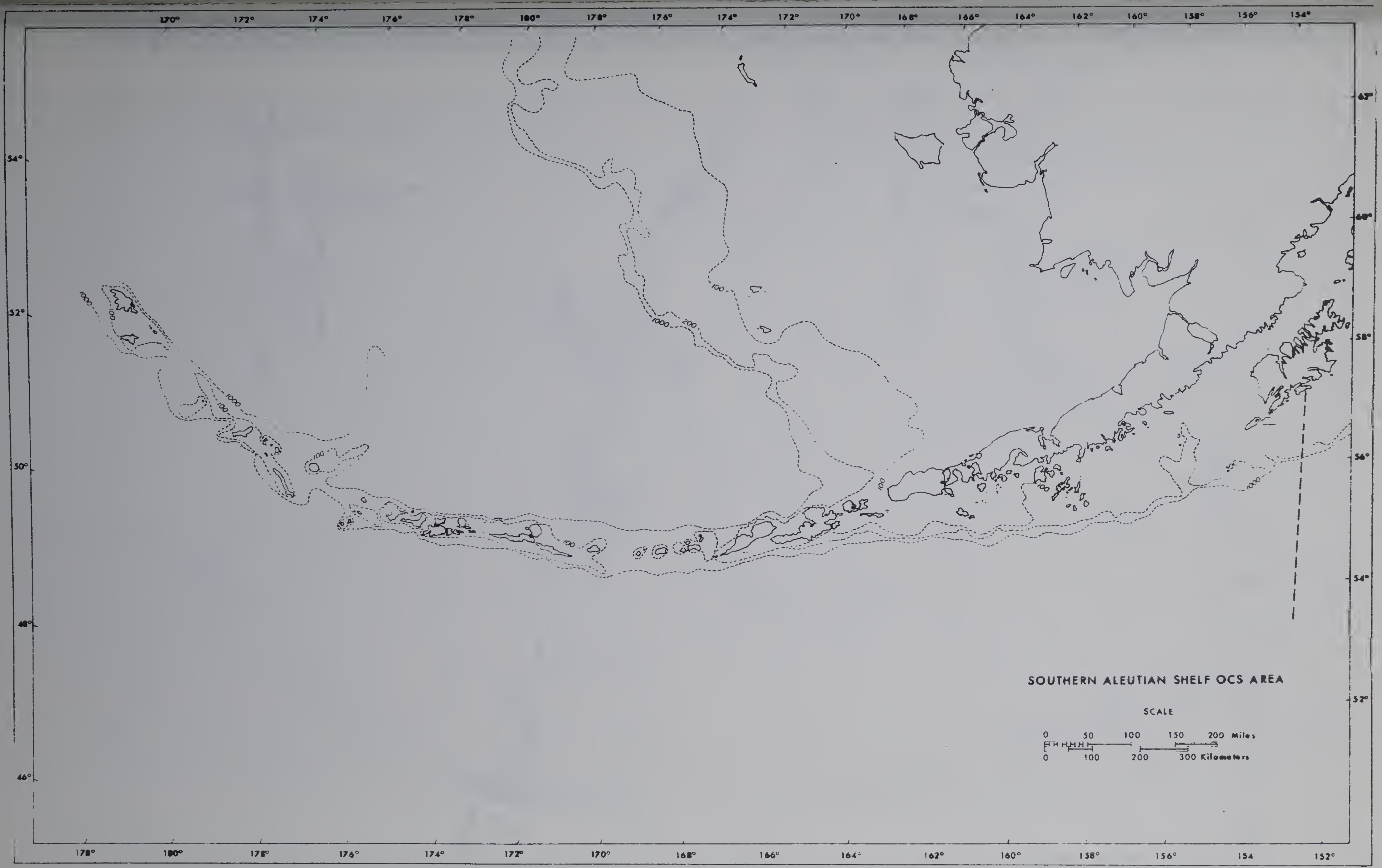
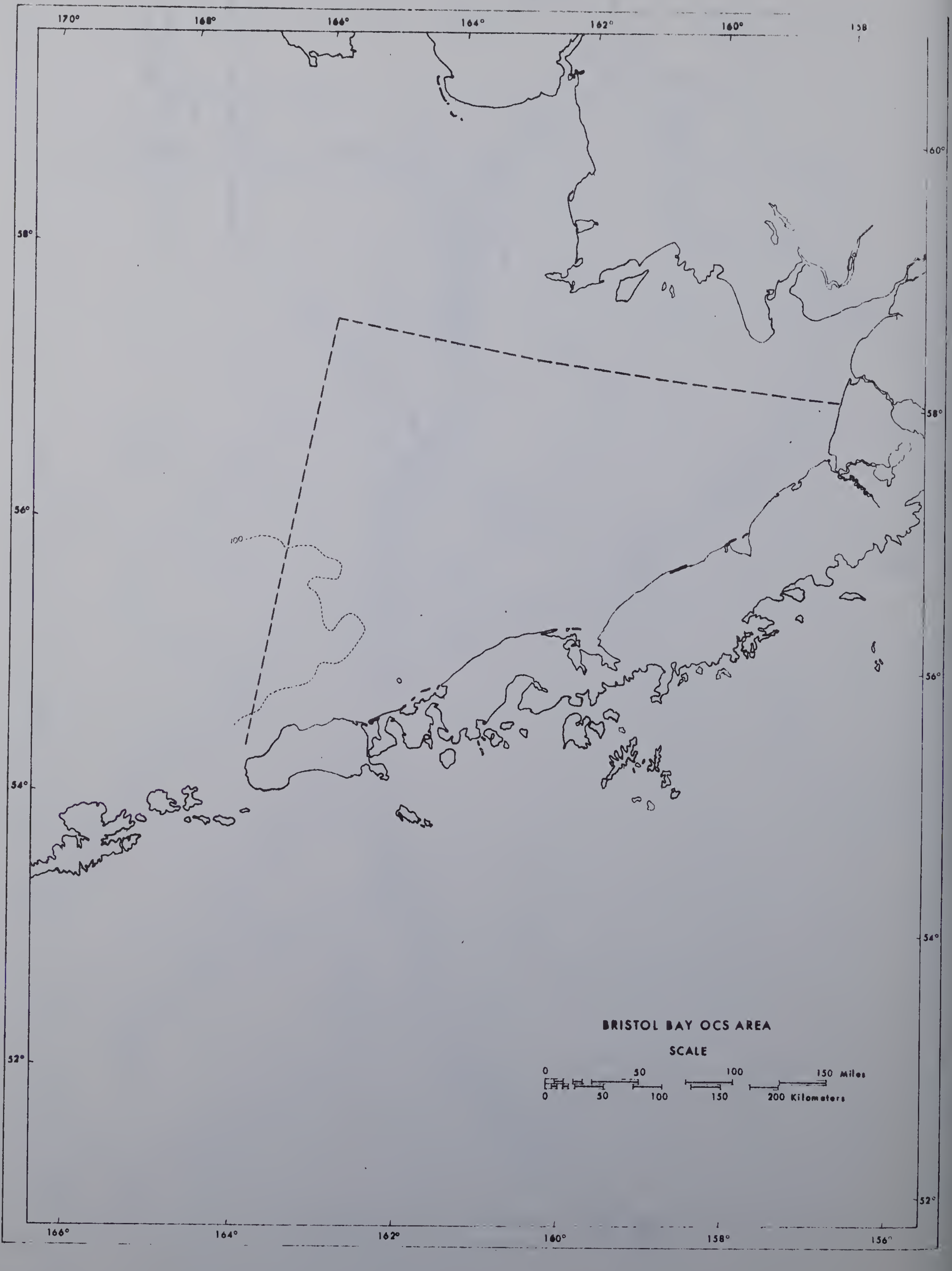
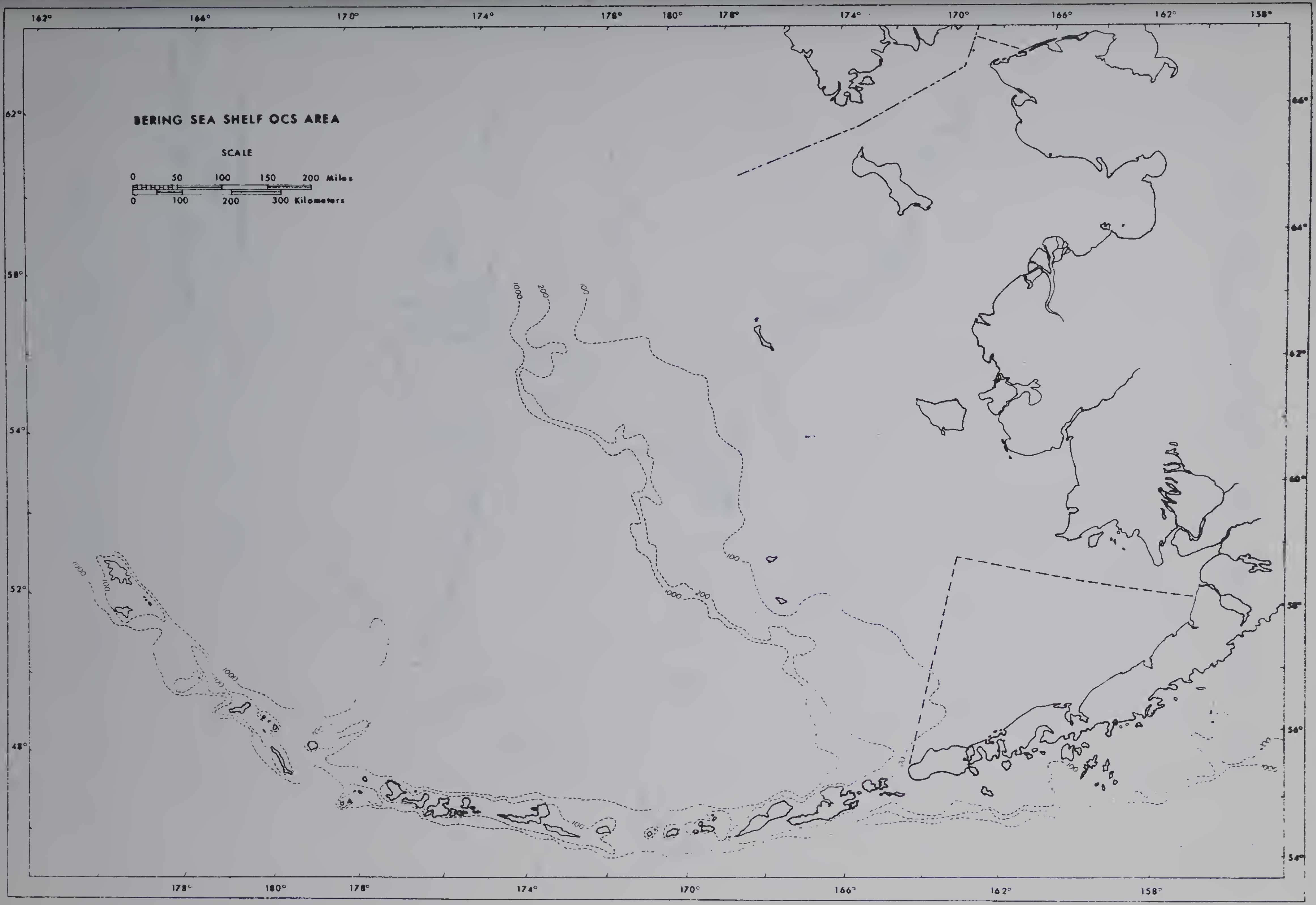
152°
150°
60°
58°
100
200
500
1000



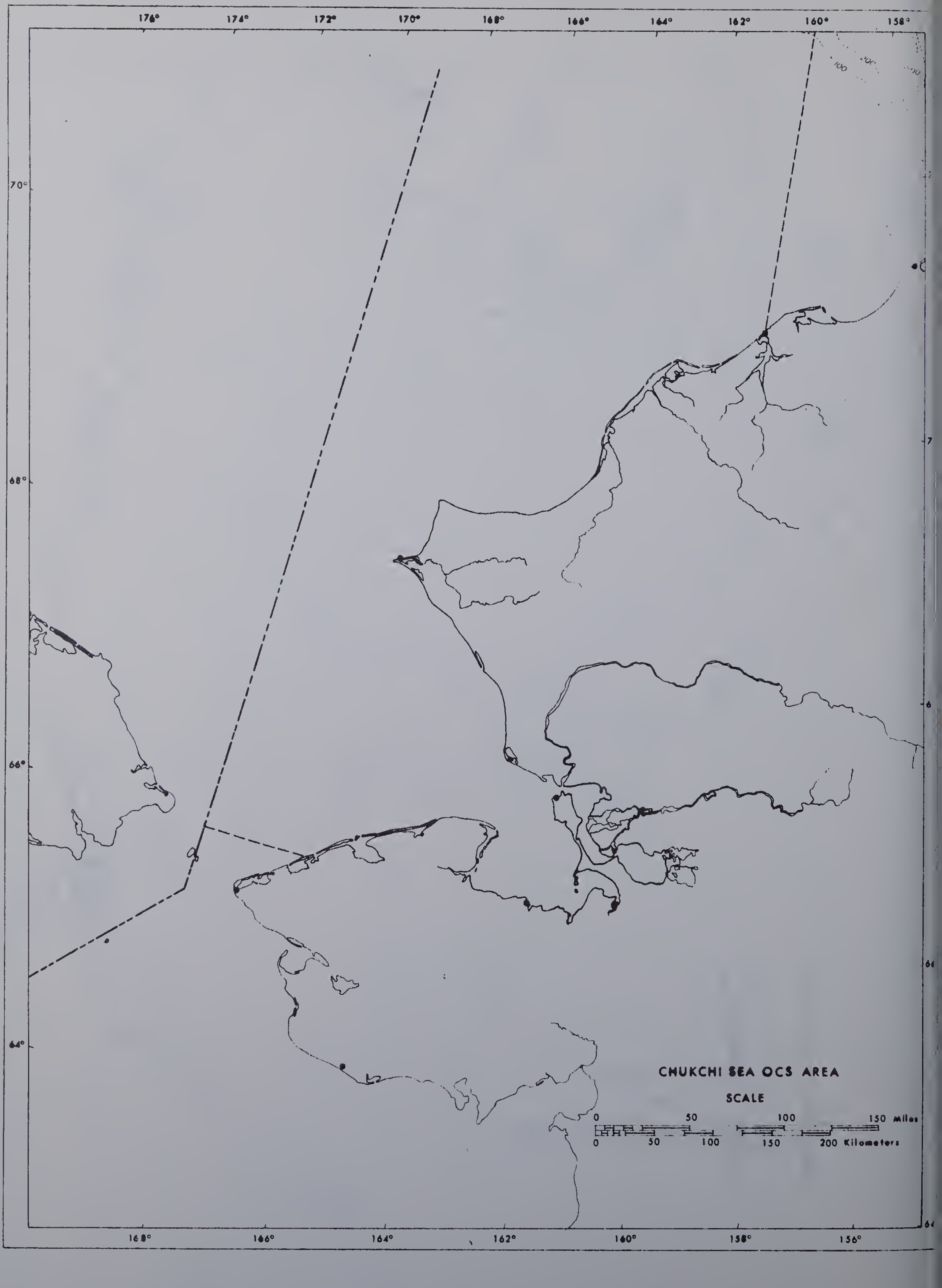
SOUTHERN ALEUTIAN SHELF OCS AREA



BRISTOL BAY OCS AREA



BERING SEA SHELF OCS AREA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164°
162°
160°
158°
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CHUKCHI SEA OCS AREA
SCALE
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150 Miles
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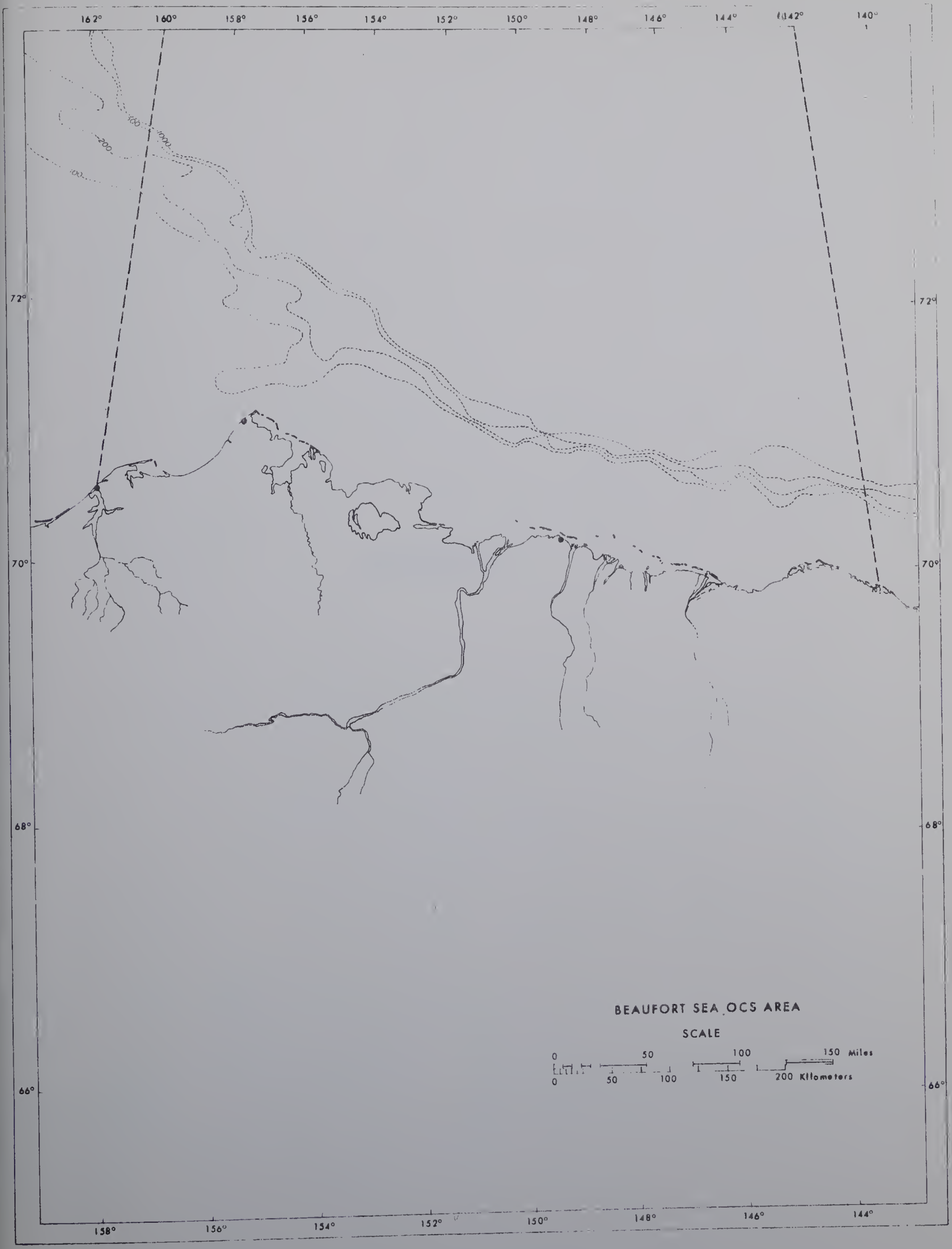
50
100
150
200 Kilometers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140°
72°
70°
68°
66°
100
200
500
1000
BEAUFORT SEA OCS AREA
SCALE
0 50 100 150 Miles
0 50 100 150 200 Kilometers
158°
156°
154°
152°
150°
148°
146°
144°

ATTACHMENT H

JUN 1974

REPORT

ON THE

RESPONSES RECEIVED IN REPLY TO THE REQUEST

FOR

COMMENTS ON POTENTIAL FUTURE

OUTER CONTINENTAL SHELF OIL AND GAS LEASING

Prepared by
BUREAU OF LAND MANAGEMENT
U.S. DEPARTMENT OF THE INTERIOR

Ed Hastey
Acting Associate Director

639 ~~644~~ (1415)

HIGHLIGHTS

(As summarized from comments received)

- Responses: Industry, conservation and other interest groups, Federal agencies, State and local governments, private citizens.
- Results: Ranking of the OCS areas according to resource potential, leasing priority, and environmental concern.
- Greatest resource potential: (17 areas): Gulf of Alaska followed by central Gulf of Mexico and Beaufort Sea; Washington-Oregon OCS least resource potential.
- Leasing priority: (17 areas): Middle Atlantic first followed by Gulf of Alaska and Cook Inlet; Washington-Oregon OCS was last.
- Composite of above rankings: (17 areas): Central Gulf of Mexico followed by Gulf of Alaska; and west Gulf of Mexico; Washington-Oregon OCS was last.
- Environmental Hazards: Least potential danger to west Gulf of Mexico followed by the central and east Gulf of Mexico. The greatest environmental concern was expressed for the Alaskan OCS.
- Constraints to Production: Industry cites shortages of tubular goods, steel, drilling platforms, personnel as constraints.
- Environmental Groups: Cite need for more data collection and analysis with regard to frontier areas before leasing takes place in these areas.
- State and local governments: Cite pending litigation between Atlantic States and Federal Government that must be settled before leasing. Local governments stress need to protect environment adjacent to their areas.

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B. Nature of the data received

C. Ranking of the OCS areas by resource potential, leasing preference, and composite ranking

D. Ranking of the OCS areas with regard to environmental concern

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643 (over)

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Report on the responses received by the Bureau of Land Management in reply to the Request for Comments on Potential Future Outer Continental Shelf Oil and Gas Leasing

I. ABSTRACT

On February 20, 1974, in the Federal Register, there appeared a request for comments from all concerned groups on potential Outer Continental Shelf (OCS) oil and gas leasing (see Attachment I). The Bureau of Land Management and Geological Survey reviewed all the responses received and has determined several rankings of the 17 OCS areas that were delineated in the Federal Register Notice, on the basis of the responses. The Bureau received 63 responses, 25 of which were from oil or related industries. The remainder of the responses were from environmental groups, State and local governments and from private citizens. Detailed reviews of these responses follow in the remainder of this report.

In general, the oil companies responded with a ranking of the areas according to resource potential although a few companies also ranked the 17 OCS areas according to their individual preferences. Some of the companies, but not all, presented mapped data. Those which did so outlined areas of interest rather than individual geologic structures. Also, some companies, but not all, gave estimates as to time periods required to achieve initial and peak production and identified factors that may be constraints to development in the OCS areas. Although a

ranking according to environmental concern was requested in the Federal Register Notice, this particular request was not specifically directed toward the petroleum companies. Nevertheless, a few companies did submit a ranking according to relative degree of environmental hazard and this ranking as well as the others (ranking according to resources potential, leasing preference, and composite ranking) are presented in the text.

Specifically requested from environmental groups was a ranking of the areas according to environmental concern. None of the responses from environmental groups, however, presented this ranking. The consensus was that not enough information on the consequences of offshore development is available to make such a ranking. Likewise, the environmental groups which responded indicated that there is not sufficient information to indicate on maps specific environmental features or hazards. Instead, most of the responses called for increased study and analysis of the OCS environment before any decisions on leasing are made. The National Wildlife Federation (NWF) referred to the thousands of miles of estuarine shoreline and called for the protection of all these vital areas. NWF also discussed some guidelines they would like to see implemented to prevent pollution of the offshore environment during all stages of exploration, production and transportation. In response to the request for specific actions which may be taken to reduce or eliminate potential conflicts in certain areas between hydrocarbon activities and other activities in the areas, the National Oceanic and Atmospheric Administration and the Department of Transportation provided some guidelines. These, too, are presented in the text.

II. GENERAL PURPOSE OF THIS REPORT

In order to implement President Nixon's directive to lease 10 million acres in 1975, within acceptable environmental standards, and in order to implement more fully the purposes and objectives of the Outer Continental Shelf Lands Act, all concerned parties representing the oil and gas industry and the general public were invited to submit information concerning areas of interest for offshore oil and gas leasing and to identify problem areas. This has been done in order to help ensure that limited resources for exploration and development can be employed in the most promising areas consistent with environmental safeguards.

The specific regions that comments were to be directed towards are the following 17 Outer Continental Shelf (OCS) areas: North, Middle, and South Atlantic; East, Central, and West Gulf of Mexico; Southern California Borderland, Santa Barbara, North and Central California, Washington-Oregon; Cook Inlet, Southern Aleutian Shelf, Gulf of Alaska, Bristol Bay, Bering Sea Shelf, Beaufort Sea, Chukchi Sea. See Attachment II, Figure 1 for a map of these locations.

The information requested from industry included the following: (1) rank the areas by order of oil and gas potential, (2) outline of geologic structures of areas of interest shown on appropriate maps (the Federal Register Notice specified that responses would be held confidential upon request), (3) estimated time periods required to achieve initial and peak production after a discovery is made, and identification of factors constraining development. The information requested concerning environmental factors included: (1) ranking according to environmental concern, (2) indication of specific environmental hazards to be considered, and (3) specific actions which may be taken to reduce or eliminate potential conflicts with oil and gas exploration and development activities.

The following is a report on all comments received from the petroleum and related industries, Federal agencies, State and local governments, and conservation groups. Because of the proprietary nature of some of the industry responses, company names are not identified with particular responses.

III. INDUSTRY RESPONSES

A. List of Companies Which Replied

The following companies responded to the request to express their views on the issues listed above.

Amoco Production Company

Atlantic Richfield Company

BP Alaska Exploration, Inc.

Cities Service Oil Company

Consolidated Edison Company of New York, Inc.

Continental Oil Company

Exxon Company, USA

Florida Gas Company

General Crude Oil Company

Getty Oil Company

Gulf Oil Corporation

Home Petroleum Corporation

International Corporation for Finance and Development

Marathon Oil Company

Mobil Oil Company

Phillips Petroleum Company

Shell Oil Company

Signal Oil and Gas Company

Southern California Gas Company

Standard Oil Company of California (Chevron)

Sun Oil Company

Tenneco Oil Company

Texaco, Inc.

Texas Eastern Transmission Corporation

Union Oil Company of California

B. Nature of the Data Received

These companies responded in varying degrees of detail both in regard to the narratives submitted, the quality and quantity of data, and maps of areas of interest on the OCS.

Each company has submitted data, maps, or information in its own particular format. Fifteen companies submitted maps. These maps varied greatly in detail; some indicated particular tracts of interest to the companies; others outlined regional geological structures and/or anomalies, whereas some indicated only general areas of interest. The companies submitted rankings of OCS areas by resource potential as requested. In addition, four companies have included in their responses other measures such as the desirability of one area over another for leasing because one area may meet their particular needs better than another area regardless of petroleum potential. Three industry rankings are presented on the next few pages: 1) by resource potential, 2) desirability of OCS areas with regard to leasing priorities, and 3) a composite list of the OCS areas with the most desirable areas listed first.

C. Ranking of the OCS Areas by Resource Potential, Leasing Preference and Composite Ranking

The ranking below is by resource potential of the OCS areas with those areas of greatest potential ranked first and the least potential ranked last.

Table 1

Rank by Resource Potential from the Greatest to the Least

1. Gulf of Alaska
2. Central Gulf of Mexico
3. Beaufort Sea
4. Bristol Bay
5. Southern California Borderland
6. East Gulf of Mexico
7. West Gulf of Mexico
   Mid Atlantic
9. North Atlantic
10. Santa Barbara
11. Bering Sea
12. Chukchi Sea
13. Cook Inlet
14. South Atlantic
15. Southern Aleutian Shelf
16. North and Central California
17. Washington-Oregon

Of the 25 industry responses, four petroleum companies ranked the frontier OCS areas according to relative leasing priority which follows; the ranking is in order of preference. (A frontier area is an OCS area in which no previous oil and gas development has occurred.)

Table 2

Ranking by Order of Preference with Most Preferred Frontier Areas Listed First

1. Mid-Atlantic
2. Gulf of Alaska
3. Cook Inlet*
4. Santa Barbara*
5. North Atlantic
6. Bristol Bay
7. Beaufort Sea
8. Chukchi Sea
9. Southern Aleutian Shelf
   South Atlantic
10. Bering Sea Shelf
11. North and Central California*
12. Washington-Oregon*

*Although there is development in Cook Inlet and Santa Barbara and there have been single lease sales off Washington-Oregon and North and Central California, they were ranked by the four companies, and, so, are included in this table.

If the two previous rankings are combined with one list indicating resource potential and leasing priority, the following is the result with the most desirable areas listed first:

Table 3

Rank in Order of Resource Potential and Order of Preference (Composite Ranking)

1. Central Gulf of Mexico
2. Gulf of Alaska
3. West Gulf of Mexico
4. Southern California Borderland
5. Mid-Atlantic
6. East Gulf of Mexico
7. North Atlantic
8. Bristol Bay
9. Beaufort Sea
10. Santa Barbara
11. Cook Inlet
12. Bering Sea
13. South Atlantic
14. Chukchi Sea
15. Southern Aleutian Shelf
16. Northern-Central California
17. Washington-Oregon

See Attachment II for a general map (Figure 1) of the 17 OCS regions, and see Figure 2 for the general locations of areas of interest within these regions. Attachment III is the matrix used in arriving at the above list and the reader is referred to this attachment.

D. Ranking of the OCS Areas With Regard to Environmental Hazard

Although no companies were requested to provide environmental rankings of the areas, four companies did rank areas according to environmental hazard. These four rankings are summarized and listed in order of increasing environmental hazard. Although factors affecting the environmental rankings were identified, a detailed analysis was not submitted. The Council on Environmental Quality (CEQ) report 1/ released in April 1974 also included rankings of certain OCS areas. They are presented for quick comparison. However, note that the CEQ report and subsequent rankings were concerned only with the Atlantic and Gulf of Alaska OCS.

Table 4

Industry Rank of Environmental Hazard from Least to Greatest	CEQ Rank of Environmental Hazard from Least to Greatest
1. West Gulf of Mexico 2. Central Gulf of Mexico	Eastern Georges Bank (North Atlantic) Southern Baltimore Canyon (Mid-Atlantic)
3. East Gulf of Mexico 4. Northern-Central California	Western Georges Bank (North Atlantic) Central Baltimore Canyon (Mid-Atlantic)
5. South Atlantic 6. Southern California Santa Barbara	Northern Baltimore Canyon (Mid-Atlantic) Southeast Georgia Embayment (South Atlantic)
7. North Atlantic Mid-Atlantic	Western Gulf of Alaska Eastern Gulf of Alaska
8. Washington-Oregon	
9. Cook Inlet	
10. Chukchi Sea	

1/ OCS Oil and Gas - An Environmental Assessment, A Report to the President by the Council on Environmental Quality, April 1974. The report is in response to the President's April 18, 1973, directive asking CEQ to work with the Environmental Protection Agency in consultation with the National Academy of Sciences and other Federal agencies, to study the impact of oil and gas production on the Atlantic OCS and in the Gulf of Alaska.

11. Beaufort Sea

12. Bering Shelf
    Gulf of Alaska

13. Bristol Bay

Most of the 25 petroleum companies expressed belief that they could function in any OCS area under necessary environmental constraints for environmental protection. The majority of these companies referenced their past performance as proof of their capabilities.

E. Discussion of Related Factors

The following is a discussion of related factors such as time to initial production, time to peak production, material shortages, etc., as viewed by industry. Companies indicating extremely long periods to peak production, generally based their estimates on peak production for the entire area. Refer to Attachment IV for a tabulation of this information.

North Atlantic

Estimated time periods to achieve initial production after a discovery is made ranged from 3 to 8 years. The majority of estimated time periods to achieve peak production after a discovery ranged from 5 to 10 years with one oil company estimating 25 years for the entire area.

Specific factors that could constrain development in this area included shortages of drilling equipment, tubular goods, personnel, capital, and platform fabricating facilities, environmental restrictions, logistics due to distance from existing supply points, State-Federal litigation, existence in heavy shipping areas, fog conditions in summer months, and political constraints in relation to environmental protection.

Mid-Atlantic

Estimated time periods to achieve initial production after a discovery is made fell in a 3-to-8-year range. Most respondent's estimates for time periods to achieve peak production after a discovery is made ranged from 5 to 10 years; however, two oil companies estimated 18 and 25 years for the entire area.

Specific factors that could constrain development in this area included shortages of rigs, steel, personnel, capital, and platform fabrication facilities, environmental restrictions, logistics due to distance from existing supply points, State-Federal litigation, and political constraints in relation to environmental protection.

South Atlantic

Respondents estimated that it would take from 3 to 8 years for initial production to occur after a discovery is made. Most oil companies' estimates for time periods for peak production to be achieved after a discovery is made ranged from 5 to 10 years, with two companies estimating 15 and 25 years for the entire area.

Possible constraints on development reported were shortages in rigs, tubular goods, platforms, labor, and capital, environmental restrictions, and political constraints in relation to environmental protection. Although existing technology is adequate for exploration and production on the Southeast Georgia Embayment, the extreme water depths in the Blake Basin would require perfected deepwater technology. Because this area is hurricane prone, some delays/shutdowns in operations might occur during storm seasons.

Eastern Gulf

Respondents noted that an average range of 3 to 4 years would be required to initial production, although certain firms felt that as much as 5 to 8 years could be required in certain instances. Most respondents felt that 6 to 8 years would be the average range to peak production; however, two firms felt 15 years to peak production was more accurate with two other firms observing that a minimal 4 to 6 years to achieve peak production would be required.

Several firms mentioned various constraints, including supply limitations on rigs, platforms, etc., while others noted skilled labor shortages, capital restrictions, and Department of Defense (DOD) constraints, such as conflict with Defense Warning Areas. One firm also made mention of environmental restrictions and regulations as being affirmative constraints, and another noted that if subsea completions were required for production, considerable testing would be required.

Central Gulf

Respondents noted that timing to initial production would be within the 2 to 4 year range, while time to peak production was estimated at 4 to 8 years. One firm noted, however, that production would be quite immediate (less than one year). Another firm differentiated between the oil peak and gas peak, noting that the latter would be a function of drilling completion and pipeline connection.

Of the constraints specifically mentioned, only general materials supplies were noted by a very few firms. One firm noted that if subsea completions for production were to be required, considerable experimentation should be forthcoming.

Western Gulf

Respondents noted that an average range of 2 to 4 years would be required to initial production (from discovery), and 5 to 8 years would be the average range required to obtain peak production, although one firm felt that as much as 10 years would be needed for peak level production. Constraints mentioned included supply constraints on rigs, platforms, etc., and conflicts with DOD operations. Additionally, labor shortages were seen by one firm as a potential constraint, and one firm noted that if subsea completions were required for production, considerable testing should be forthcoming.

Southern California Borderland

It was noted by most respondents that the timing to initial production (after discovery) would be approximately 3 years, while peak production would occur approximately 8 years after initial discovery. However, a significant percentage of those companies responding stated that peak production could come between 10 and 15 years after discovery. Further, two firms felt that water depth would be the most important variable in both initial and peak production.

The principal constraints included the limited supply of rigs, tubular goods, platforms, and high seismic activity, with several firms noting that deep-water technology (beyond 1500 feet) may require several years to develop.

Santa Barbara Channel

Respondents noted that the timing to initial production would be about 2 to 4 years after discovery, with peak production coming within the 5-to-8 years range, although a single firm felt peak production would occur 12 years after discovery.

Constraints for this area included earthquake danger, some supply limitations on tubular goods, steel, etc., with some firms noting that subsea drilling and completion in deeper waters at greater distances from shore could also be a potential constraint.

Northern and Central California

Respondents noted timing to initial production would be about 3 to 4 years after discovery, although there was a very wide range of estimates of timing to peak production. Over 60% of the firms felt that peak production would occur between 5 and 7 years; over 25% of all firms estimated a range of 10 to 20 years to achieve peak production for the area.

Few firms noted specific constraints, with limited supply of tubular goods, rigs, and possible earthquake danger being explicity mentioned.

Washington-Oregon

Timing to initial production was generally 3 to 4 years, although two firms felt it would require as much as 6 years after discovery to achieve initial production. Six to 9 years was the range to peak production for most firms, but 3 firms estimated that it would not be achieved until 12 to 20 years after discovery.

Few firms mentioned specific constraints, but a few expressed concern over deeper water depths in excess of 600 feet, plus possible logistical problems, limited supply of tubular goods, somewhat poor weather, and seismic activity.

Cook Inlet

Estimated time periods to achieve initial production after a discovery is made ranged from 2 to 7 years. The majority of estimates for time periods to achieve peak production were between 4 and 8 years; two companies estimated the period to be 15 and 20 years for the entire area.

Specific factors that could constrain development include remoteness from supply sources and markets, limited gas market, need to construct gas pipelines and shore facilities, prohibition on gas flaring, State-Federal ownership litigation, severe tides, environmental restrictions, and shortages of rigs, platforms, steel, personnel, and capital. Also the introduction of earthquake/ice problems will require new designs and increased safety guidelines for equipment and personnel for the Alaska offshore.

Southern Aleutian Shelf

Responses on the timing of initial production after discovery ranged from 3 to 8 years. Most companies indicated that peak production would be achieved within 6 to 12 years after discovery; one estimate was 20 years and another was 25 years for the entire area.

Shortages of rigs and platforms, high costs, severe sea and weather conditions, and limited gas markets would act as constraints on development. Large inventories of equipment and supplies must be maintained because of remoteness from supply points as well as interruptions from supply points in severe storms. One company noted that North Sea technology supplemented with earthquake design engineering would allow relatively safe operations in shallow water areas where the sea bottom is not dissected.

Gulf of Alaska

Respondents indicated a time period ranging from 3 to 8 years for initial production to occur after discovery. Estimates for peak production after discovery averaged 10.5 years with two oil companies estimating 20 years for the entire area.

Constraints on development included shortages of rigs, platforms, steel, labor, and capital, limited gas markets, severe sea, weather, and seismic conditions, minor State-Federal disputes on State tidelands boundaries, and the need to maintain large inventories of supplies and equipment because of remoteness from supply sources.

Bristol Bay

Estimated time periods to achieve initial production after discovery ranged from 3 to 8 years. Estimates for peak production after discovery averaged 10.5 years with one oil company estimating 23 years for the entire area.

Specific factors that could constrain development include shortages of equipment, manpower, and capital, remoteness from market and supply sources, limited time for drilling, and severe weather conditions including ice, high winds and waves, and dense fog.

Bering Sea Shelf

Estimates for timing of initial production after discovery ranged from 3 to 10 years. Responses on timing of peak production after discovery averaged 10.7 years with one oil company estimating 25 years for the entire area.

Factors which could constrain development include the short construction season, equipment shortages, remoteness from labor and equipment supplies, limited gas markets, and severe climate including thick ice and high winds. Although one company stated that present technology is capable of coping with problems of weather and thin ice, another maintained that existing technology is inadequate in dealing with the ice conditions in the northern part of this area. Still another stated that there is no available method of producing under the severe conditions of the Arctic ice pack with the exception of man-made islands.

Beaufort Sea

Estimated timing for initial production after discovery ranges from 3 to 10 years. The average estimated time period for achieving peak production is 11.7 years with one company estimating a 30 year time frame for the entire area.

Constraints on development include the permanent ice conditions, severe climate, limited open waters in winter, short construction season, shortages of labor and equipment, remoteness from markets, high transportation costs, and the State-Federal disputed boundary around the barrier islands. Technology to handle moving ice packs may be developed by the mid- 1980's. Also, artificial islands could be built in shallow areas.

Chukchi Sea

Estimates for time periods for initial production after discovery range from 3 to 9 years. The majority of estimates on time periods for peak production after discovery fell in the 7-to-15 years range, with one company estimating 5 years and another estimating 25 years.

Constraints on development included labor and equipment shortages, severe climate and ice conditions, remote location, and the short construction season. There is no available method of producing under the severe conditions that exist with the exception of man-made drilling islands. Technology may be developed to handle moving ice packs by the 1980's.

See Attachment IV for a table of related factors which summarize this section.

IV. ENVIRONMENTAL AND OTHER GROUP RESPONSES

A. List of Respondents

The environmental groups that commented include the Alaska Conservation Society, National Wildlife Federation, Friends of the Earth, Sierra Club, Committee for Green Foothills, and the Oregon Shores Conservation Coalition. Two non-environmental groups responded which were the New England Fisheries Steering Committee and the League of Women Voters of North Carolina.

B. Discussion of Responses

None of the conservation groups or individuals that responded ranked the areas by environmental concern. The general feeling is that there is not enough information on the consequences of offshore development or environmental data available on the area for them, industry, or the general public to make such a ranking.

The need for BLM to have baseline studies in all the areas before making any decisions on leasing was stressed. These groups feel that at least three years of baseline studies are needed to adequately understand and protect the environment.

The most detailed of the environmental groups responses was from the National Wildlife Federation (NWF). In their letter of May 1, 1974, the NWF listed guidelines they would like to see implemented in order to protect the environment from damage during operations to extract oil and gas. These are:

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1. Use of environmentally safe sound wave generating equipment
2. Finding a better way to dispose of drilling cuttings other than dumping in the water
3. Keeping a closer watch on the disposal of materials off the side of the platforms.
4. Employee education program to help prevent mistakes that lead to spills.
5. Better monitoring for blowout prevention
6. Improved pipeline construction techniques to minimize environmental damage
7. Improved tanker technology to prevent oil spills
8. Improved methods for oil spill clean-up operations.

The Sierra Club expressed concern about many areas, but stated, "Under a drastically accelerated program of offshore leasing, meaningful evaluation of 'areas of greatest environmental concern' and 'potentially significant environmental factors' is all but impossible." In the response from the Sierra Club were discussed some areas of "particular biological productivity, diversity or uniqueness". But, the Sierra Club warned that although the list is the best possible under the circumstance it is incomplete and patchy. Finally, the Club urged that "the Departmen of the Interior not embark on any massive offshore development programs until adequate data is available on which to make reasonably informed judgements about the degrees of risk and benefit involved".

V. FEDERAL AGENCY, STATE GOVERNMENT, LOCAL JURISDICTION RESPONSES

A. List of Responses

Responses were received from the following Bureaus within the Department of the Interior regarding offshore areas: 1) United States Geological Survey, 2) the Bureau of Mines, 3) the Bureau of Outdoor Recreation, 4) the National Park Service, and 5) the Bureau of Sport Fisheries and Wildlife. Responses were received from the following Federal agencies: 1) National Oceanic and Atmospheric Administration, 2) Department of Defense, 3) Federal Energy Administration, and 4) Federal Power Commission. In addition, the Council on Environmental Quality's report on environmental considerations in the Atlantic OCS and the Gulf of Alaska, ordered by the President in April 1973, was released in April 1974. The reader is referred to the CEQ study for their assessment of environmental impacts on the Atlantic and Gulf of Alask OCS (also see the CEQ OCS ranking on p. 10 of this report).

B. Discussion of Federal Agency Responses

In addition to the Request for Comments that appeared in the Federal Register, the Bureau of Land Management requested resource reports from the aforementioned Bureaus within the Department of the Interior. In the request for resource reports, these Bureaus were asked to submit comments and data on their respective areas of concern. Summaries of each of these resource reports are given in the following text.

The USGS prepared a comprehensive geologic report on the structure and resource potential of each of the OCS areas. The United States Geological

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Survey has estimated (March 1974) that offshore petroleum recoverable resources in the OCS to 200 meters water depth as yet undiscovered total 58 to 116 billion barrels. Undiscovered recoverable gas resources are estimated to be 355 to 710 trillion cubic feet.

The Bureau of Mines prepared an analysis of the supply and demand of petroleum until 1980. It is predicted that the demand for oil in 1980 will be 20.8 million barrels per day and for gas 34.5 trillion cubic feet per day. However, supply is estimated at 11.7 million barrels per day and 20.4 trillion cubic feet per day. These projections were made, of course, before Project Independence and the recent directive by the President to accelerate the OCS leasing program. In the present day tight petroleum supply situation, markets for petroleum are characterized by greater demand than supply. Depending on location of resources, certain patterns of processing and consumption likely would develop. That is, oil production from the Atlantic OCS would most likely be processed in refineries along the Atlantic seaboard and consumed in nearby eastern States. Likewise, gas from the Atlantic OCS would also be consumed in these areas. Similarly, production in the Pacific OCS would probably be processed and consumed in the Pacific seaboard and adjacent States. Increased oil production in the Gulf of Mexico is expected to be refined in Gulf coast refineries as is currently being done. Because of past activity in the prolific Gulf of Mexico hydrocarbon areas, an extensive network of pipelines carries hydrocarbons to many areas of the country. Gulf of Mexico hydrocarbons serve 36 of the 48 coterminous States. Presumably some of the increase in production that would result from accelerated activity in the Gulf of Mexico within a few years will serve to satisfy the increased demand for petroleum in Gulf Coast States, but the remainder will likely be piped to the other States that depend on Gulf of Mexico oil and gas. Alaskan production probably will be processed on the Pacific seaboard for consumption in Pacific and western States.

The National Park Service, the Bureau of Outdoor Recreation, and the Bureau of Sport Fisheries and Wildlife have categorized according to location some of those Historic Sites, National Park areas, refuges, fishing areas, etc., that would be impacted by hydrocarbon activity. These reports have noted that the possible oil and gas lease sales in OCS areas represent many potential threats to the recreation environment. These reports assume a constant threat of damage from oil leakage or spills. The report also observes that construction of pipeline terminal stations and related road and facilities could eliminate some future opportunities for water-oriented outdoor recreation. They note that platforms and rigs visible from shore can have negative visual impacts and that their construction and operation may result in oppressive noise or objectionable odors.

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Besides the resource reports requested from other Bureaus within the Department, the Bureau of Land Management contacted other Federal agencies for their responses to the questions asked in the *Federal Register* Notice. The agencies contacted were: 1) the Department of Commerce, 2) the Department of Defense, 3) the Department of Transportation, 4) the Department of Treasury, 5) the Environmental Protection Agency, 6) Federal Power Commission, and 7) the Federal Energy Amdinistration. The Council on Environmental Quality report on the environmental effects of OCS development on the Atlantic and Gulf of Alaska OCS areas was transmitted to the Department during the same period that other agency comments were requested. This report is now being reviewed in detail. The following is a summary of responses of other agencies received by the Bureau of Land Management.

The National Oceanic and Atmospheric Administration (NOAA) (Department of Commerce) has provided data gathered in relation to fisheries in the Gulf of Mexico, the South Atlantic and the Pacific. In these reports, they call for the following specific actions to preserve fishing resources from potential damage from hydrocarbon development activities. All of these actions have been implemented or are being considered by the Department.

1. Wells and platforms should not be located in coral reef areas.
2. Platforms should not be located on steep slopes, as these are prime fishing areas for species such as snappers and groupers.
3. Drill cuttings and muds should be discharged so as to settle outside areas of productive benthic assemblages.
4. Submerged wellheads should be capped below the surface of the ocean floor or well marked with buoys.

5. Wells should be spaced far enough apart to permit trawling operations in the area.
6. All construction debris should be removed and disposal should be onshore.
7. Pipelines to onshore facilities should be consolidated into pipeline corridors.
8. Pipeline corridors should be located so that they do not traverse estuaries or that they traverse the least sensitive estuarine area. Productive bays and marshes should not be disturbed.
9. Pipelines should be buried beneath the ocean floor. Where they cannot be buried, they should be well marked with buoys and all buoys must be maintained.
10. In areas where obstructions already exist on the bottom, wells should be located near the obstructions to reduce further loss of fishing grounds available to the trawl fishery.
11. Onshore facilities must be located outside productive estuarine systems.

In addition, NOAA recommended that in order to preserve unspoiled water environments, there should be no haphazard array of development sites. Rather, the sites of hydrocarbon activity should be arranged, to the extent possible, in small clusters separated by no less than 50 miles. NOAA observed that density greater than this will increase the severity of effect upon fisheries and other marine estuarine resources.

The Department of Defense stated a preference for reviewing each leasing proposal on a case-by-case basis as they have done previously. Therefore, DOD did not wish to issue a commentary that would be inclusive of the entire OCS.

The U.S. Coast Guard (Department of Transportation) made the following comments in regard to OCS leasing. The Bureau of Land Management should avoid leasing in navigation routes but if necessary, consideratio might be given to relocating such things as traffic separation schemes and ocean dumping areas where feasible and reasonable. The response from DOT mentioned that there are fishing areas listed in the Code of Federal Regulations, but it appears that there is no regulation to isolate the fishing areas from the leasing of oil and gas properties.

The Federal Power Commission discussed what they consider may well be th primary policy question to be decided with respect to future OCS leasin programs. This question is whether to focus attention on the frontier area of greatest potential i.e., Alaska, or to lease acreage in each of the major offshore areas with the goal of obtaining a more diffuse supply. To develop the Alaska OCS may be the most economically efficient method but, if the areas for development are more diverse, the Nation will have a more assured supply of petroleum. In regard to environmental protection, the FPC called for greater cooperation among agencies and advanced planning to reduce potential conflict between environmental protection and oil and gas activity.

The Treasury and Federal Energy Office had no specific comments, but promised full cooperation if needed in the future.

C. Discussion of State Level Responses

Responses were received from:

Maine	Gov. Kenneth Curtis
New Hampshire	Gov. Meldrim Thomson, Jr.
New Jersey	Gov. Brendan Byrne
Delaware	Gov. Sherman Tribbitt
Maryland	Gov. Marvin Mandel
Virginia	Gov. Mills Godwin
North Carolina	Gov. James Holshouser, Jr.
California	Gov. Ronald Reagan Director, Department of Fish and Game

Most of the Governors of the Atlantic States called for deferring leasing action on the Atlantic OCS until such time as any litigation is concluded between the States and the U.S. Government over jurisdiction. Most of the Governors, in fact, suggested that priority be given to Gulf of Mexico and other areas and that Atlantic OCS leasing be forestalled. California advocates the resumption of drilling off its shores but only under the strictest environmental and safety regulations. None of the Governors provided any specific detailed information. However, some indicated that they may be inclined to respond with other information after resolution of the jurisdictional disputes.

D. Discussion of Local Jurisdiction Responses

Four responses were received from local jurisdictions, all in objection to any possible hydrocarbon activity at or near their locales. The city of Portmouth, New Hampshire, requested more environmental analyses, but the cities of Manhattan Beach, Rancho Palos Verdes, and Hermosa Beach, California, are unconditionally opposed to any offshore hydrocarbon activity.

VI. PRIVATE CITIZEN, OTHER RESPONSES

A. Discussion of Private Citizen Responses

About a dozen private citizen responded to the *Federal Register* Notice. The responses can be divided into two categories: those from the West Coast and those from New York. Responses from the West Coast called for further study of environmental systems. Note was made that the time period allowed for acceleration of offshore leasing (i.e., 10 million acres to be leased in 1975) is not sufficient even to identify areas of environmental concerns, much less perform detailed environmental analyses. One letter called for an inventory of marine resources; and the need to accelerate data-gathering right along with the acceleration of leasing so that environmental data will be gathered in sufficient quantity to keep up with leasing.

The responses for private citizens in New York were collected by Congressman John J. Rooney of New York. These letters from residents of Congressman Rooney's district were, without exception, opposed to any drilling off the coast of Long Island.

B. Discussion of Other Responses

Letters were received from three members of the U.S. House of Representatives: Congressman Gerry E. Studds, Massachusetts;

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Congressman Charles A. Vanik, Ohio; and Congressman John J. Rooney, New York.

Congressman Gerry E. Studds:

Congressman Studds' comments referred to the Gulf of Alaska, North Atlantic, and environmental values. Concerning the Gulf of Alaska, the point was made that the Council of Environmental Quality (CEQ) Report states that more data is needed concerning biological, physical, chemical, technological, economic, and social parameters in that area.

With regard to the North Atlantic, specifically Georges Bank, Congressman Studds referenced the CEQ report and its comments to the effect that little is known about the potential biological impacts of oil spills on fisheries of that area. It was also pointed out that in 1961, Congress identified the seaward shore of Cape Cod as an area of national environmental importance when it created the Cape Cod National Seashore. Therefore, more data is needed concerning the likely movement of any possible oil from spills that might occur in that region.

Congressman Charles A. Vanik:

Congressman Vanik directed his remarks to the proposed accelerated OCS leasing program. The Congressman does not favor elimination of offshore leasing for oil and gas, but questions the proposal to lease 10 million acres of the OCS in 1975. Congressman Vanik questioned the justification of accelerated leasing, and if acceleration comes about, what should be its extent; concern was also expressed about the benefits of accelerated leasing, the costs that must be balanced such as environmental values, the need for more energy, and alternates to the proposed action. The question was also raised about economic and technical constraints that face industry in developing the OCS under an accelerated schedule and steps that will be taken to meet these constraints. He stressed the need for an environmental impact statement on the 10 million acre proposal.

Congressman John J. Rooney:

Congressman Rooney submitted nine letters from residents of his Congressional District for the purpose of informing the Department of their views on developing oil and gas resources in the North Atlantic. The general theme of these letters was that the authors are against such activities off the shores of New York.

Congressman Rooney's comments were to the effect that he is intersted in the subject, and solicits the Department's views.

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VII. CONCLUSIONS

In addition to the requested ranking of resource potential, some companies ranked the 17 OCS areas according to leasing priority and environmental values. The area generally considered to have the greatest resource potential is the Gulf of Alaska followed by the Central Gulf of Mexico. The area of least resource potential is the Washington-Oregon OCS.

Four companies ranked the frontier OCS areas according to leasing priority. The Middle Atlantic was ranked first followed by the Gulf of Alaska. The area of least interest in this regard is the OCS off Washington-Oregon.

A composite of both of these rankings, i.e., resource potential and leasing priority, results in a ranking of areas with the Central Gulf of Mexico first followed by the Gulf of Alaska, Western Gulf of Mexico, Southern California Borderland, and the Mid-Atlantic ranked as fifth. The OCS off Washington-Oregon again ranks last.

With regard to environmental values, four companies ranked the OCS areas environmentally.

The area of least environmental hazard is the entire Gulf of Mexico; the area of greatest concern is the Alaskan OCS with Bristol Bay representing the greatest environmental concern. Most companies stated that they can operate in an environmentally safe manner as indicated by past performance.

Various factors were indicated to be constraints on the development of the OCS, i.e., rig availability, casing, personnel, capital, platforms, etc. The companies state that it will generally take 2-8 years for initial production to initiate in new sale areas after discovery of petroleum resources, and from 5-10 years for peak production. However, a few companies state that the necessary time for peak production to occur in some OCS areas will take 20-30 years.

The environmental groups did not rank the OCS areas, but they observed that more data gathering and analysis is necessary before leasing occurs in frontier areas. In fact, these groups feel that our present knowledge is of such a limited nature, that ranking the areas according to environmental values is not possible.

Of the governmental agencies that responded, the Federal agencies submitted the most information which dealt with guidelines and safeguards. State and local governments generally submitted comments to the effect that leasing should not occur until resolution of litigation and until more baseline studies involving environmental values are concluded.

Responses from private citizens were generally opposed to leasing in frontier areas.

The Department of the Interior intends to use the information summarized in this report as well as information from the CEQ study of the Atlantic and Gulf of Alaska OCS areas, other studies, including the baseline studies that Interior will soon have underway in frontier areas, and discussions with concerned State officials and representatives of industry and environmental groups to determine which frontier OCS areas should be developed. All development actions will be conducted in full compliance with the requirements of the National Environmental Policy Act of 1969.

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VIII APPENDIX

Notices

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

POTENTIAL FUTURE OUTER CONTINENTAL SHELF OIL AND GAS LEASING

Request for Comments

In order to implement President Nixon's directive to lease ten million acres in 1975, and in order to implement more fully the purposes and objectives of the Outer Continental Shelf Lands Act, all concerned parties representing the oil and gas industry and the general public are invited and encouraged to submit information concerning areas of interest for offshore oil and gas leasing and to identify problem areas. This is being done in order to help ensure that scarce resources for exploration and development can be employed on the most promising areas consistent with environmental safeguards. Regulations or procedures necessary to implement the other actions announced by the President in his Energy Message relating to Outer Continental Shelf (OCS) leasing will be subsequently published for public comment before they become effective and are not part of this request for comment.

Oil and gas resources of the continental margin, including those beyond the 200 meter depth contour, subject to jurisdiction of the United States are to be considered. Precise continental shelf boundaries between the U.S. and opposite or adjacent states have not, with some exceptions, been agreed. Accordingly certain areas are or may be subject to dispute. No decision has been made to undertake leasing in actually or potentially disputed areas while efforts are being made to reach agreement with the nations concerned. In this connection reference is made to the last sentence of Department of State Public Notice 320, appearing in 35 FR 3301 of February 20, 1970.

Leasing in the Cook Inlet of Alaska and on the Atlantic OCS is contingent on resolution of the litigation between the Federal Government and the State of Alaska and Atlantic coastal states regarding areas of jurisdiction or an alternative resolution of the issues. Further, the President's Council on Environmental Quality is conducting studies of the environmental impact of oil and gas production on the continental shelf of the Atlantic Ocean and the Gulf of Alaska. No leasing in these areas will be permitted unless it is determined that oil and gas exploration and development can proceed in an environmentally satisfactory manner. However, information concerning OCS areas of interest is being requested at this time in order to identify areas of special resource potential and of environmental value. It is the intention of the Department of Interior to conduct a call for tract nominations on more specific areas after consideration of the comments resulting from this request and, where appropriate, after resolution of State/Federal jurisdiction disputes and a determination from the CEQ Atlantic and Gulf of Alaska studies tha development can proceed in those area in an environmentally satisfactory manner. Information received in response t this request will also be considered i determining future leasing plans.

The areas to be commented on are a follows:

	Approximate location
Atlantic Coast OCS areas:	
1. North Atlantic	Bay of Fundy to Cape Code north of 40° N latitude and south of.[1]
2. Mid-Atlantic	Cape Cod to Cape Hatteras between 40 N. t 35° N. latitude.
3. South Atlantic	Cape Hatteras to Key West south of 35° latitude.
Gulf of Mexico OCS areas:	
4. East Gulf	East of 88° W. longitude.
5. Central Gulf	Between 88° W. to 93° W. longitude.
6. West Gulf	West of 93° W. longitude to Mexican border.
Pacific OCS areas:	
7. Southern California Borderland	South of 34° N. latitude to Mexican bord (except Santa Barbara Channel).
8. Santa Barbara	Santa Barbara Channel.
9. North and Central California	North of 34° N. latitude to California-Orego border (except Santa Barbara Channel).
10. Washington-Oregon	Between California-Oregon border and Can dian border.
Alaska OCS areas:	
11. Cook Inlet	South of 60° N. latitude.
12. Southern Aleutian Shelf	West of 153° W. longitude.
13. Gulf of Alaska	North of 58° N. latitude, east of 153° longitude.
14. Bristol Bay	South of 58° N. latitude, east of 165° longitude.
15. Bering Sea Shelf	U.S. waters south of 66° N. latitude.
16. Beaufort Sea	Between 142° W. and 160° W. longitude.
17. Chukchi Sea	U.S. waters north of 66° N. latitude, west 160° W. longitude.

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[1] The line drawn from a point at: 42°19.9′ N. latitude, 67°46.9′ W. longitude, thence to 42°9.3′ N. latitude, 67°40.0′ longitude, thence 41°42.4′ N. latitude, 67°28.8′ W. longitude, and ending at 41°15.3′ latitude, 66° 58.9′ W. longitude.

Other Areas of interest may be commented upon by appropriate area designation.

AREAS OF OIL AND GAS RESOURCE POTENTIAL

The following information is requested:

1. Rank by order of oil and gas potential the areas of interest listed above.

2. Outline of geologic structures of areas of interest shown on appropriate maps. All such information will remain confidential on request. Bureau of Land Management official leasing maps may be obtained from: (1) Gulf of Mexico Outer Continental Shelf Office, Suite 3200, The Plaza Tower, 1001 Howard Avenue, New Orleans, Louisiana 70113; (2) Pacific Outer Continental Shelf Office, 300 North Los Angeles Street, Los Angeles, California 90012; or, (3) Alaska Outer Continental Shelf Office, 121 Firewood Lane, Room 270, P.O. Box 11 Anchorage, Alaska 99510.

3. For each area of interest, estimat time periods required to achieve init and peak production after a discovery made, and identification of specific f tors that may constrain development i these areas.

AREAS OF ENVIRONMENTAL CONCERN

The following information is r quested:

1. Rank with areas of greatest en ronmental concern first the above ar and indicate specific environmental v ues which exist and damages wh might be incurred.

2. If possible, indicate the location maps of specific environmental featu or hazards to be considered in th areas if their resource potential is de

oped (locations where maps can be obtained listed above).

3. Indicate specific actions which may be taken to reduce or eliminate potential conflicts with oil and gas exploration and development activities.

The information should be submitted no later than May 1, 1974, in envelopes or packets marked "Request for Comments on Potential Future, Outer Continental Shelf Oil and Gas Leasing." The information should be submitted to Director, Attention 730, Bureau of Land Management, Washington, D.C. 20240. Copies of the information should also be sent to the Chief, Conservation Division, No. 600, U.S. Geological Survey, National Center, Reston, Virginia 22092.

GEORGE C. TURCOTT,
Associate Director,
Bureau of Land Management.

Approved: February 15, 1974.

JOHN C. WHITAKER,
Acting Secretary of the Interior.

[FR Doc.74-4126 Filed 2-15-74;4:51 pm]

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ATTACHMENT II

Figure 1 indicates the 17 Outer Continental Shelf (OCS) areas for which information was requested. Figure 2 indicates the general areas of interest within the 17 OCS regions; these general areas of interest are not drawn to scale. These general areas of interest as placed on the map of Figure 2, were determined from maps submitted by 15 oil companies; the general areas of interest are summarized as follows:

Areas	Total	Companies that Expressed General Regional Interest	Companies that Expressed Particular Areas of Interest within the Region
North Atlantic	13	11	2
Mid-Atlantic	13	11	2
South Atlantic	12	10	2
Eastern Gulf of Mexico	13	9	4
Central Gulf of Mexico	12	8	4
Western Gulf of Mexico	13	7	6
Southern California Borderland	14	9	5
Santa Barbara	10	9	3
North-Central California	11	9	2
Washington-Oregon	10	7	3
Cook Inlet	14	13	1
Gulf of Alaska	15	14	1
South Aleutian Shelf	11	10	1
Bristol Bay	15	14	1
Beaufort Sea	14	13	1
Bering Sea	13	12	1
Chukchi Sea	12	11	1

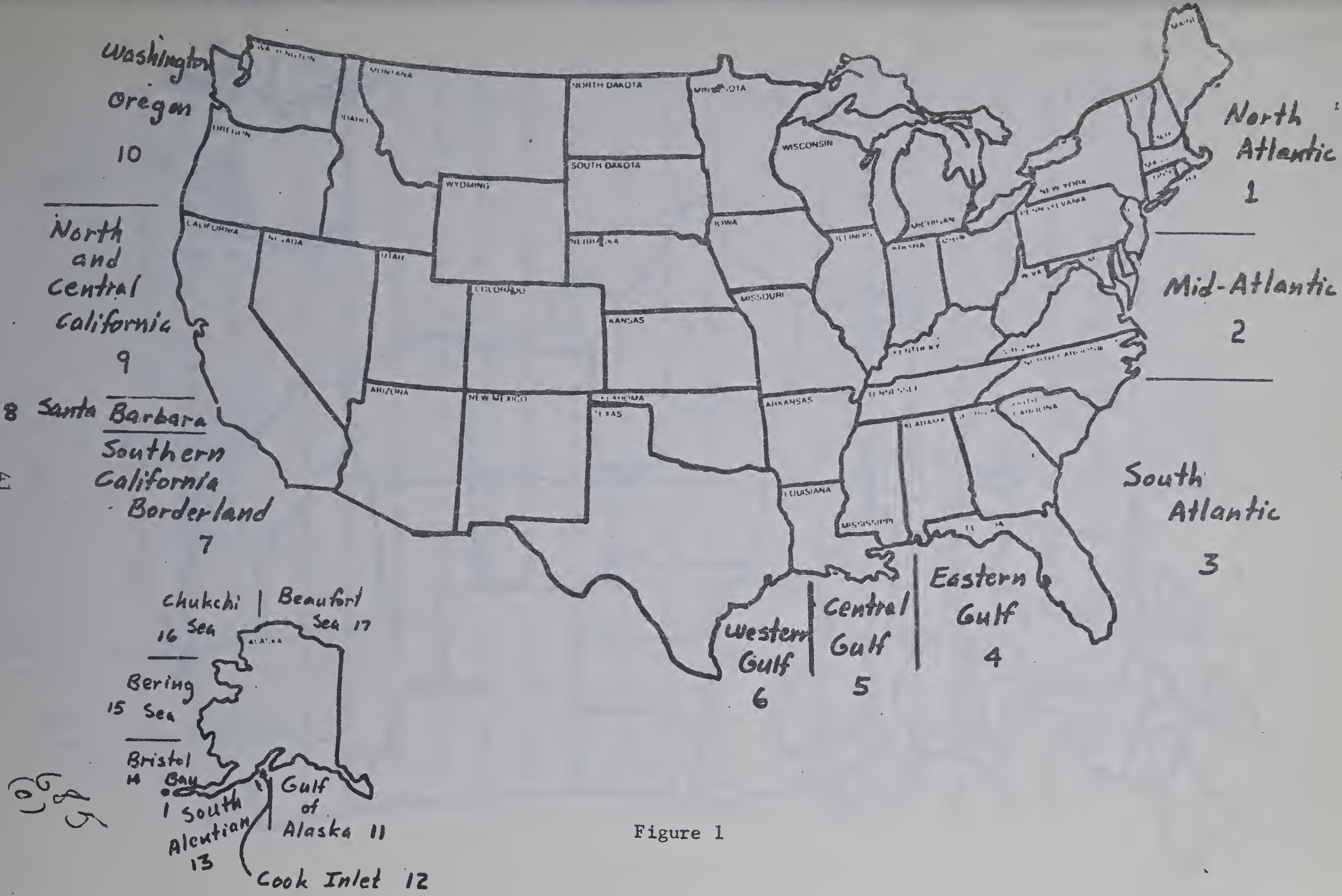
Washington Oregon 10
North and Central California 9
8 Santa Barbara
Southern California Borderland 7
North Atlantic 1
Mid-Atlantic 2
South Atlantic 3
Eastern Gulf 4
Central Gulf 5
Western Gulf 6
Chukchi Sea 16
Beaufort Sea 17
Bering Sea 15
Bristol Bay 14
South Aleutian 13
Gulf of Alaska 11
Cook Inlet 12
WASHINGTON
OREGON
CALIFORNIA
NEVADA
IDAHO
MONTANA
WYOMING
UTAH
COLORADO
ARIZONA
NEW MEXICO
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
MINNESOTA
IOWA
MISSOURI
ARKANSAS
LOUISIANA
WISCONSIN
ILLINOIS
MICHIGAN
INDIANA
OHIO
KENTUCKY
TENNESSEE
MISSISSIPPI
ALABAMA
GEORGIA
FLORIDA
SOUTH CAROLINA
NORTH CAROLINA
VIRGINIA
WEST VIRGINIA
PENNSYLVANIA
NEW YORK
MAINE
ALASKA

Figure 1

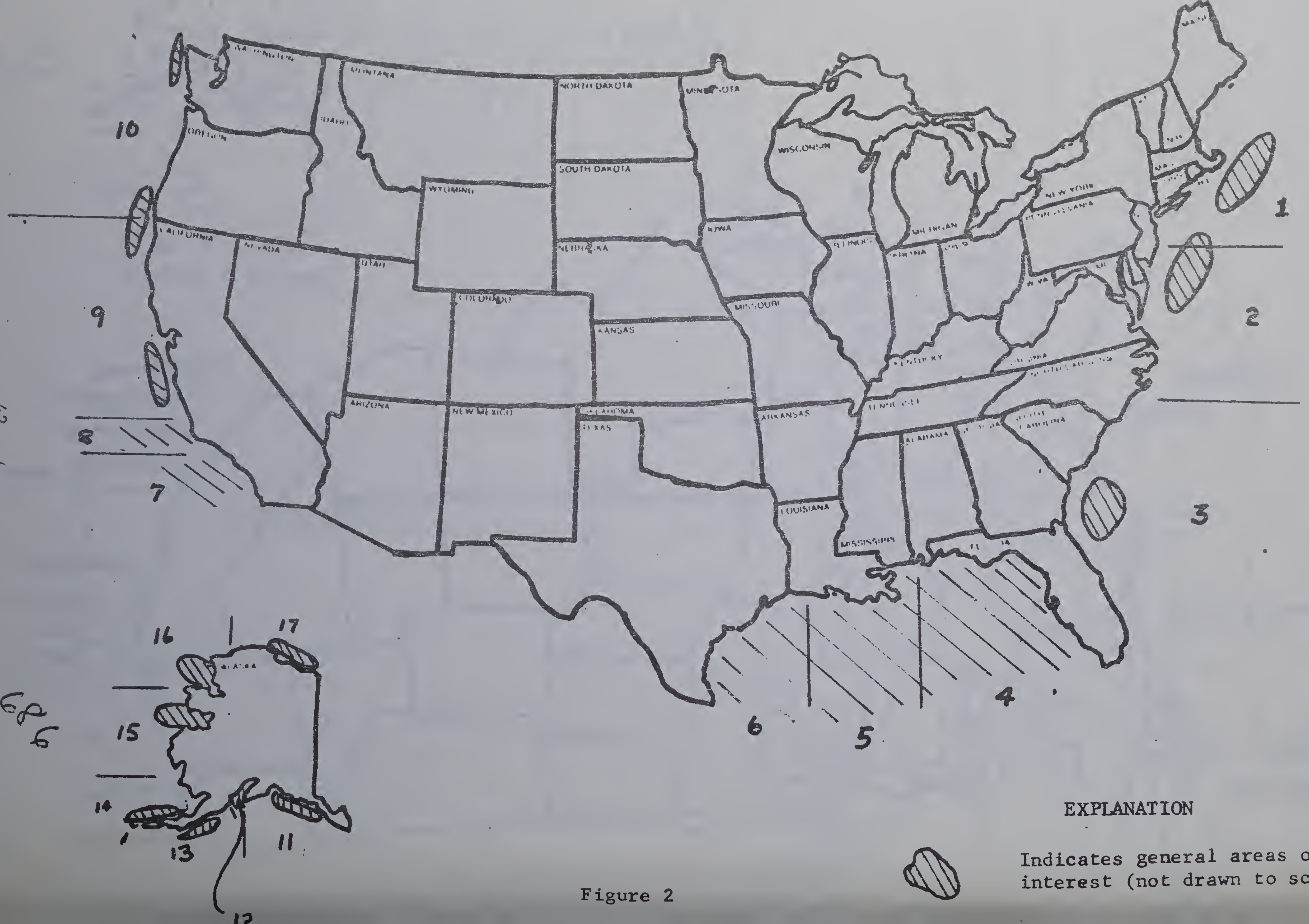

Figure 2

EXPLANATION

▨ Indicates general areas of interest (not drawn to scale)

ATTACHMENT III

Following is the matrix used in arriving at the composite list. The rows of the matrix are simply the numbered rankings submitted by each company for each OCS area. The numbers in the column titled "Average" are simple averages calculated from the sum of the digits in each row divided by the number of entries in that row. The lowest average was 3.82 (Central Gulf of Mexico) meaning that the Central Gulf of Mexico is highest in the companies' priorities. The corresponding rank of each of the 17 areas is given in the column titled "Rank".

Of 25 industry or related responses, only 22 ranked the areas; three did not submit a ranking scheme; one company's list was not suitable for inclusion in the matrix. That is, that company divided the 17 OCS areas into three groups, each group with a high priority and a low priority. Group I was Atlantic Coast - Gulf of Mexico and the highest priority was the Central Gulf of Mexico. Group II was Pacific Coast and the highest priority was Santa Barbara. Group III was Alaska and the highest priority was the Gulf of Alaska. Because of this arrangement, this particular company's rankings were omitted from the matrix, leaving 21 companies whose rankings were included.

Some companies did not rank all 17 OCS areas. For this reason, averaging each row was necessitated rather than a simple summation of the digits in each row. For example, the North Atlantic was included in the rankings of only 20 of the 21 companies whose lists are included in the matrix. Therefore, the sum of the digits in the row "North Atlantic" is 131. Dividing by 20 entries yields 6.55, the number appearing in the "Average" column.

It should be noted that of the 21 companies included in the matrix, 19 of these companies listed the areas according to resource potential. However, four companies listed the areas according to desirability for leasing. Two of these four companies listed separately resource potential and desirability and for both companies, only their lists according to resource potential were entered into the matrix. The other two companies ranked the areas only according to desirability and did not provide a ranking strictly by resource potential. For these two companies, their desirability rankings were included in the matrix, even though 19 others were ranked by resource potential.

Thus, the following matrix was constructed and used to determine the composite ranking of 17 OCS areas according to information supplied by industry.

OCS Areas	Composite Ranking by Company (Companies not named)																					Average	Rank
North Atlantic	11	10	1	8	8	7	4	x	10	5	13	2	4	6	3	7	8	9	8	6	1	6.55	7
Mid-Atlantic	9	6	2	9	7	6	x	x	9	10	14	6	3	5	2	5	4	11	5	3	2	6.21	5
South Atlantic	16	11	9	12	14	8	3	x	14	13	15	11	8	15	11	8	11	16	10	11	5	11.05	13
East Gulf of Mexico	7	3	10	1	15	5	2	x	6	7	10	10	5	4	5	4	6	8	4	x	8	6.32	6
Central Gulf of Mexico	13	1	3	7	1	x	1	x	5	1	1	4	x	1	7	1	1	3	6	x	9	3.82	1
West Gulf of Mexico	4	8	4	11	4	1	5	x	7	2	5	9	13	2	8	3	2	5	11	x	10	6.00	3
Santa Barbara	10	4	6	15	11	x	x	1	16	16	2	x	x	3	10	2	16	2	15	2	12	8.41	10
Southern Calif. Borderland	5	7	5	2	10	2	x	3	2	4	3	x	12	9	12	10	3	4	7	x	11	6.17	4
Northern-Central Calif.	14	12	12	17	12	10	x	x	13	15	11	x	14	14	15	16	15	12	16	10	13	13.39	16
Washington-Oregon	17	17	13	16	17	11	x	x	15	17	17	x	15	16	17	12	17	17	17	12	14	15.39	17
Gulf of Alaska	1	2	8	4	6	4	6	4	1	3	9	1	1	12	1	16	5	6	2	1	3	4.10	2
Cook Inlet	15	13	7	14	9	3	x	2	11	12	8	5	11	10	6	11	7	7	4	4	6	8.75	11
Southern Aleutian Shelf	12	16	14	10	16	x	x	x	17	14	16	8	10	17	16	15	12	15	9	7	15	13.28	15
Bristol Bay	6	5	11	5	3	9	x	x	8	9	6	3	2	8	9	13	9	10	3	5	7	6.89	8
Bering Sea	2	14	15	6	13	12	x	x	12	8	12	13	6	13	14	14	13	14	1	9	16	10.89	12
Chukchi Sea	8	15	17	13	5	14	x	x	4	11	7	12	9	11	13	17	14	13	13	8	17	11.63	14
Beaufort Sea	3	9	16	3	2	13	x	x	3	6	4	7	7	7	4	9	10	1	12	13	4	7.00	9

x indicates no ranking.

Note: Not all respondent companies ranked the areas and some companies did not rank all 17 areas.

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ATTACHMENT IV

Table of Related Factors - (Refer to Part III. E. Discussion of Related Factors)

OCS Area	Years to Initial Production	Years to Peak Production	Constraints
North Atlantic	3-8	5-10 (25)	Drilling equipment; tubular goods; personnel; capital; logistics; platform fabrications; litigation; heavy shipping area; fog
Mid-Atlantic	3-8	5-10 (18-25)	Rigs; steel; personnel; capital; platform fabrications; logistics; litigation
South Atlantic	3-8	5-10 (15-25)	Rigs; tubular goods; platforms; labor; capital; deepwater technology; hurricane storms
Eastern Gulf of Mexico	3-4 (5/8)	6-8 (4-6 min., 15 max.)	Rigs; platforms; labor; capital; DOD Warning Areas; possible subsea completion requirements
Central Gulf of Mexico	2-4	4-8	General material; possible subsea completion requirements
Western Gulf of Mexico	2-4	5-8 (10)	Rigs; platforms; DOD Warning Areas; labor; possible subsea completion requirements
Southern Calif. Borderland	3	8 (10-15)	Rigs; tubular goods; platforms; seismic activity; deepwater technology

OCS Area	Years to Initial Production	Years to Peak Production	Constraints
Santa Barbara Channel	2-4	5-8 (12)	Seismic activity; tubular goods; steel; subsea completion testings; deepwater technology
Northern & Central California	3-4	5-7 (10-20)	Tubular goods; rigs; seismic activity
Washington-Oregon	3-4 (6)	6-9 (12-20)	Deepwater technology; logistics; tubular goods; weather; seismic activity
Cook Inlet	2-7	4-8 (15-20)	Remote supply sources; limited gas mkt; pipelines; shore facilities; litigation; tidal activity; rigs; platforms; steel; personnel; capital; earthquake/ice
Southern Aleutian Shelf	3-8	6-12 (20-25)	Rigs; platforms; capital; weather; limited gas mkt; remote supply sources; weather; earthquakes
Gulf of Alaska	3-8	10.5 (20)	Rigs; platforms; steel; labor; caiptal; limited gas mkt.; weather; sea/sesimic; ligitation; remote supply sources
Bristol Bay	3-8	10.5 (23)	Equipment; manpower; capital; remote mkt./ supply sources; drilling time; ice; tidal activity; fog

OCS Area	Years to Initial Production	Years to Peak Production	Constraints
Bering Sea	3-10	10.7 (25)	Construction season; equpiment; labor; remote supply sources; limited gas mkt.; weather; ice; winds; technology
Beaufort Sea	3-10	11.7 (30)	Ice; weather; limited passage; construction season; labor; equipment; remote mkts., transportation costs; litigation
Chukchi Sea	3-9	7-15 (5-25)	Labor; equipment; ice; weather; remote supply sources; construction season

ATTACHMENT I

The following is a tentative designation of lease sales to be held in 1975. These designations have been developed for planning purposes only; no decisions have been made on the exact scheduling and sizing of all the lease sales under the accelerated proposal.

Sale Area	Approximate Acreage Offering (millions)
South Texas	3.0
Central Gulf	2.0 - 3.0
Southern California	1.5
Cook Inlet	2.5
Frontier (Gulf of Alaska)	Unknown
Frontier (Middle Atlantic)	Unknown

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